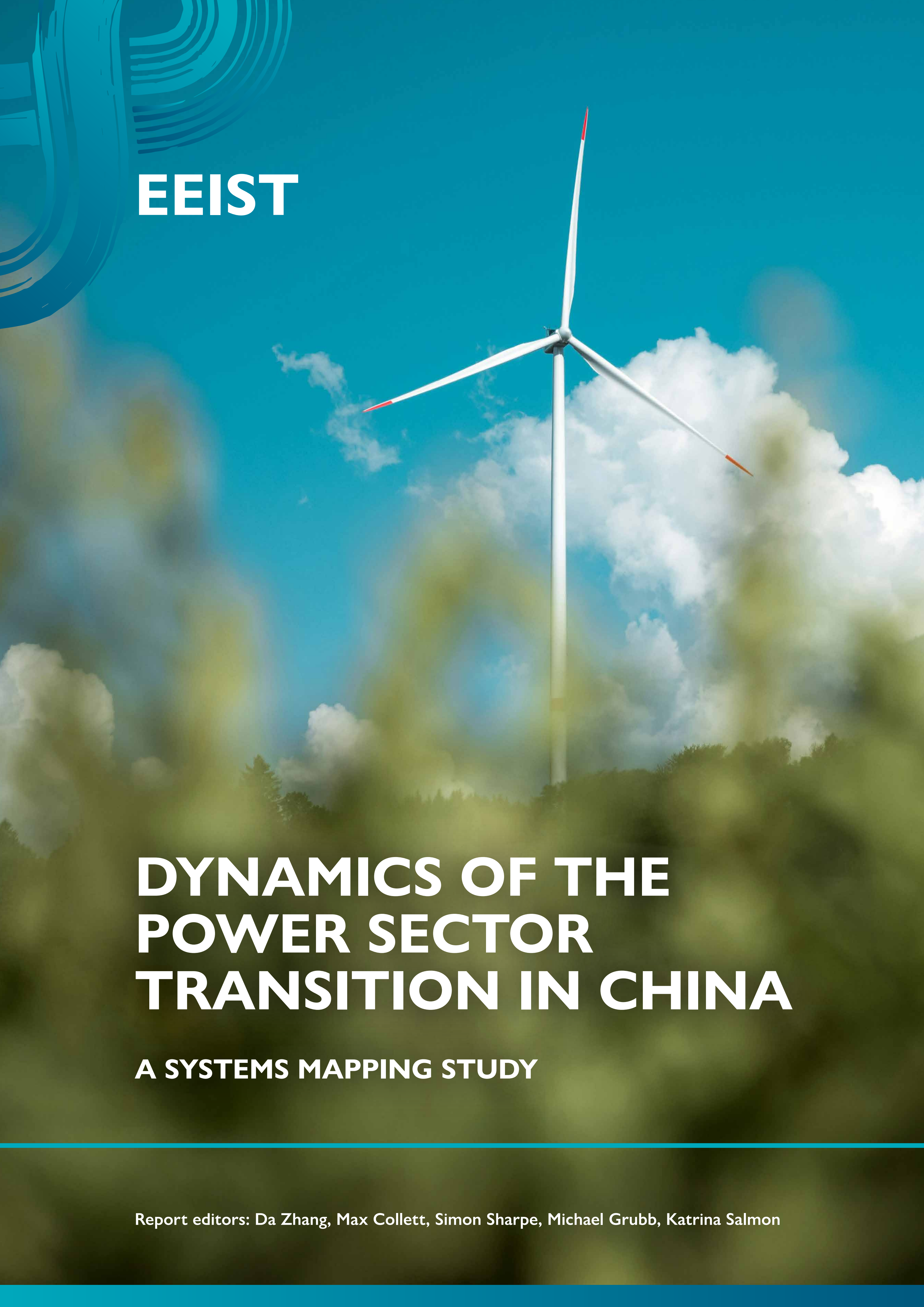

EEIST

DYNAMICS OF THE POWER SECTOR TRANSITION IN CHINA

A SYSTEMS MAPPING STUDY

Report editors: Da Zhang, Max Collett, Simon Sharpe, Michael Grubb, Katrina Salmon

EEIST

About

The Economics of Energy Innovation and System Transition (EEIST) project began in 2020 as a three-year collaboration between researchers in the UK, China, India and Brazil, with funding from the Department of Business, Energy and Industrial Strategy and the Children's Investment Fund Foundation. The aim of the EEIST project is to apply a complex systems understanding of economics to inform policymaking on the low-carbon transition.

Following this initial phase, two subsequent projects—EEIST Phase II and the EEIST China Power Sector Reform project—were launched. This report contains the main findings of the China Power Sector Reform project. The partners in this project are University College London, S-Curve Economics CIC, the University of Oxford, Tsinghua University, Beijing Normal University, and the World Resources Institute China.

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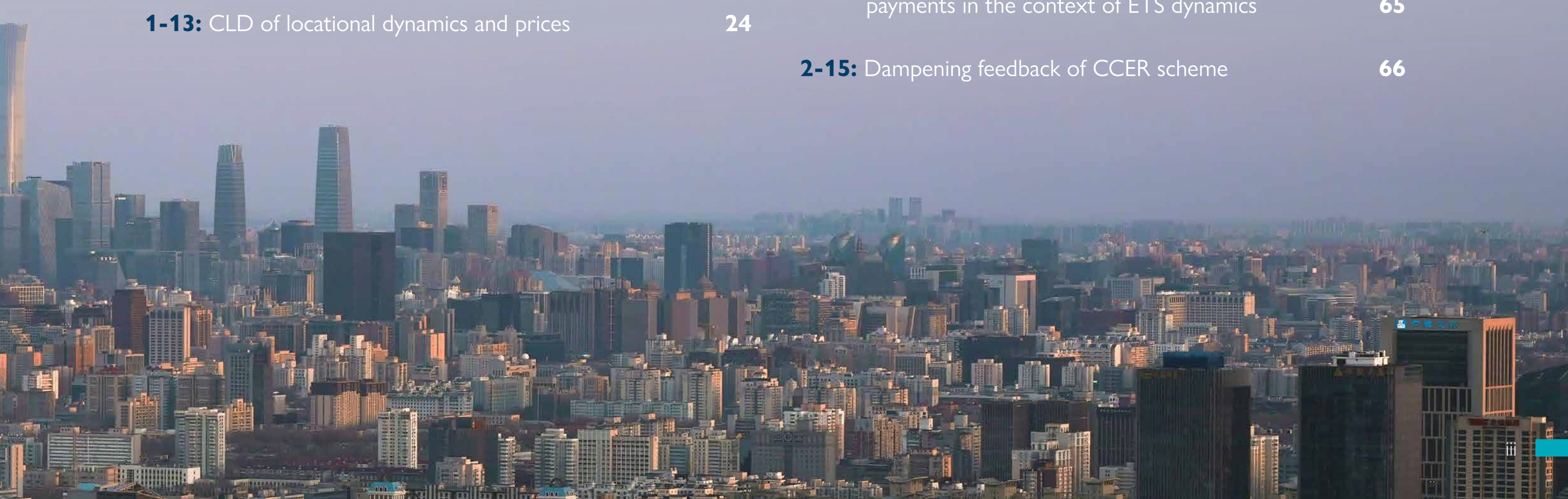

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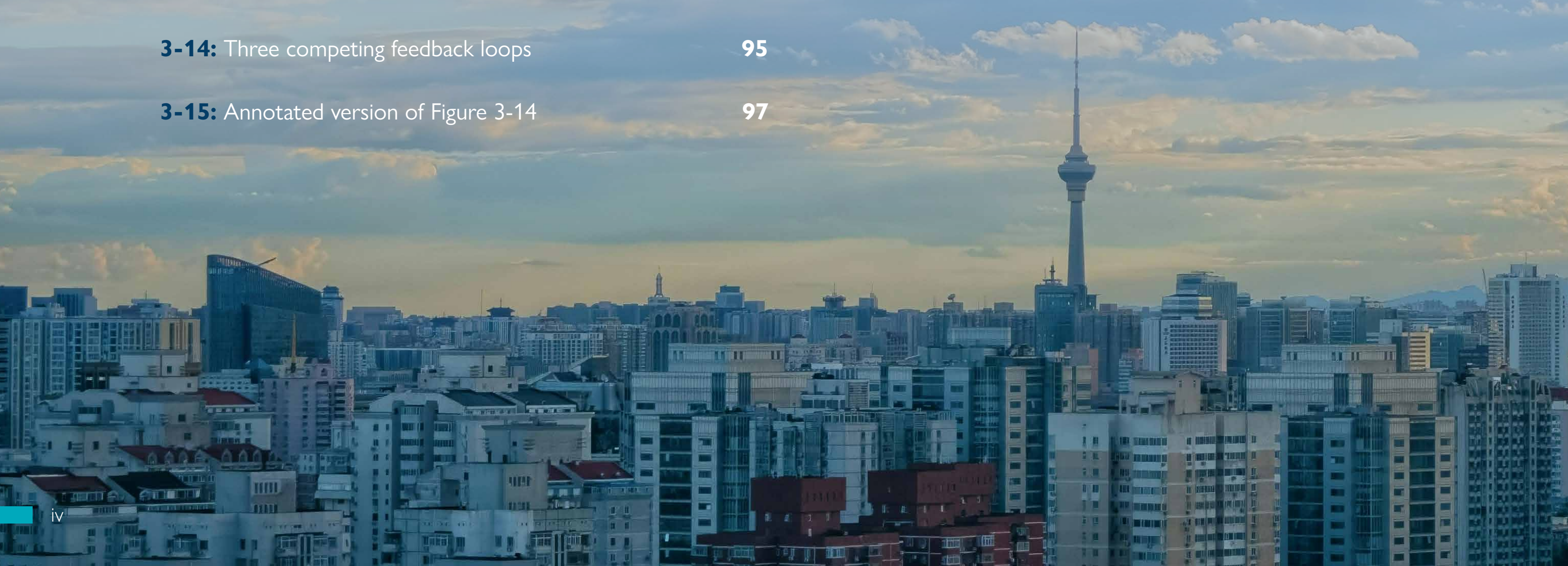

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Abbreviations

AR: Auction round
BESS: Battery energy storage system
CAGR: Compound annual growth rate
CCER: China Certified Emission Reduction
CCGT: Combined cycle gas turbine
CCS: Carbon capture and storage
CEA: Carbon emission allowance
CEC: China Electricity Council
CEGB: Central Electricity Generating Board
CfD: Contract for difference
CLD: Causal loop diagram
CM: Capacity market
CNY: Chinese yuan
DESNZ: Department for Energy Security and Net Zero
DSR: Demand side response
ETS: Emissions trading system
EU: European Union
GAC: Government-authorised contract
GB: Great Britain
GBP: Great British pounds
GEC: Green Energy Certificate
IEA: International Energy Agency
LCCC: Low Carbon Contracts Company
LDES: Long-duration energy storage
MLT: Medium- and long-term contracts
MSR: Market stability reserve
NDRC: National Development and Reform Commission
NEA: National Energy Administration
NFFO: Non-Fossil Fuel Obligation
OECD: Organisation for Economic Co-operation and Development
Ofgem: Office of Gas and Electricity Markets
PPA: Power purchase agreement
PRC: People's Republic of China
PTE: Panel of Technical Experts
PV: Photovoltaics
PVD: Peak-valley difference
REMA: Review of Electricity Market Arrangements
RESPO: Renewable Energy Siting and Power system Optimisation
ROC: Renewable Obligation Certificate
RPS: Renewable Energy Portfolio Standard
SASAC: State-owned Assets Supervision and Administration Commission of the State Council
SOE: State-owned enterprise
UK: United Kingdom
UNFCCC: United Nations Framework Convention on Climate Change
VRE: Variable renewable energy


中国平安

Executive summary

The transition to clean technologies in the power sector is fundamentally transforming energy systems, with important implications for electricity costs, carbon emissions, and security of supply.

In this context of structural change, cause and effect are often disproportionate. This leads to surprises, which may be either beneficial or detrimental for policy objectives. Understanding the causal feedback loops in the system—reinforcing feedbacks that amplify change, and dampening feedbacks that inhibit change and preserve stability—can help to anticipate policies' dynamic effects, and distinguish those that are self-amplifying from those that are self-limiting. The analysis of feedbacks can also help to identify ways in which combinations of policies are mutually reinforcing or mutually offsetting.

China is undertaking the transition to clean power on an unmatched scale, and the UK is navigating it at an exceptional pace. While China is engaged in a process of electricity market liberalisation, the UK is considering a wide-ranging set of policy reforms centred around a liberalised wholesale market. Despite their different scales, starting points, and institutional structures, the two countries now face a similar set of challenges as they aim to adapt their power systems to new technologies.

In this report, we use systems mapping with causal loop diagrams—an analytical technique focussed on feedback loops—to provide a new perspective on the dynamics of the power sector transition in China. Where relevant, we complement this with insights from the UK's experience.

Sustaining rapid growth of renewable power in the context of market liberalisation

A reinforcing feedback between investment, deployment, cost reduction, and profitability has driven non-linear growth in solar and wind power, which have greatly exceeded expectations. Keeping this feedback operating will be essential for meeting the policy goals of carbon peaking and neutrality in the power sector, and for keeping electricity costs low for consumers.

As variable renewable energy (VRE)—referring to wind and solar—provides a larger share of power generation, and as an increasing share of VRE is sold through competitive markets (instead of by guaranteed purchase), the combination of these trends brings into play a set of dampening feedback loops that risk undermining further investment in renewables. These feedbacks involve higher VRE penetration leading to i) lower prices at times of high VRE supply; ii) increased volatility of spot market prices, with less predictability of returns and potentially higher financing costs; and iii) increased volume risk, where VRE projects cannot sell their power due to technical curtailment, economic curtailment, or the supply of VRE exceeding total electricity demand.

In provinces where the renewable share of generation is highest, this may already be putting downward pressure on electricity prices, although the price of coal remains a dominant factor. There are signs of increasing price volatility in provinces with more advanced spot markets; and curtailment of renewables, after falling for many years, is again beginning to increase.

The sale of green electricity certificates (GECs) could, in principle, increase the revenues of renewables and encourage further investment. But for this effect to be realised, the price of a GEC would need to be significantly higher than its current level of around 0-3% of the coal benchmark power price. Maintaining a GEC price high enough to support investment is difficult because the policy has a built-in dampening feedback: if it succeeds in causing more renewables to be deployed, this will increase the supply of GECs, and that will tend to decrease the GEC price. Even if the GEC price were fixed, this would only partially offset one of the three dampening feedbacks that threaten to undermine investment in renewables.

The UK has found Contracts for Difference (CfDs) to be an effective instrument for breaking the dampening feedbacks of price risk and price volatility, and maintaining investment in renewables. After the introduction of CfDs in 2013, the UK's offshore wind capacity deployed and contracted increased almost sevenfold over the following decade, while at the same time the cost of offshore wind power fell by more than a factor of three.

With VRE now accounting for over a third of the UK's generation, volume risk is becoming significant. In 2023, Great Britain (GB) had 214 hours of negative prices in the day-ahead electricity market—three times the level of the previous year. By 2030, VRE output could exceed electricity demand nearly 50% of the time in the absence of any system flexibility, with around 27-37% of wind power generated in 2030 potentially being wasted. Since the UK's current CfD guarantees the price at which renewable power is sold (but only for the volume that can be sold), it does not address the risk that this could pose to further investment in renewables. Consequently, the government has been considering alternative CfD designs—a deemed CfD or a capacity-based CfD—to break or constrain the volume risk dampening feedback, whilst the flexibility of the system is enhanced to make better use of surplus generation.

In China's medium- and long-term (MLT) electricity market, a CfD-like arrangement exists that can provide certainty of price for the part of a renewable generator's output that is covered by an MLT contract, even when some of this output is sold through the spot market. But since MLT contracts are typically for one year, these cover only a small fraction of the risks that are relevant to investment in a renewable plant with a 20-year lifetime. These contracts are therefore useful for budget forecasting, but not investment.

The new CfD instrument introduced by *Document 136* in February 2025 will provide price certainty for the part of a renewable generator's output previously covered by guaranteed purchase policies, over a period of time aligned with the cost recovery of renewable investments. As renewable power generators are gradually forced to participate in market trading, the expansion of this mechanism could limit risk and price volatility feedbacks, which would support continued investment in renewable power.

Although the VRE share of generation in China nationally is around half that of the UK (19%, compared to 36%, in 2024), the provinces most advanced in the transition, such as Qinghai and Gansu, already have VRE shares similar to or higher than that of the UK, and the VRE share in all provinces is growing on a similar trajectory. We project that nine provinces could experience frequent VRE surplus events (in the range of 20-30% of the time) in 2030. This represents a significant volume risk, which, given the long payback period of VRE investments, could erode market-based revenues of VRE plants installed today.

Compared to the UK, China has an advantage of being able to experiment with different policy approaches in different provinces. We recommend encouraging provinces to experiment with alternative CfD designs, including deemed and capacity-based CfDs, to discover the most effective approaches to limiting the dampening feedback of volume risk that threatens to undermine continued investment in renewable power.

Maintaining security of supply in the context of technological change

The rapidly growing VRE share of power generation creates new challenges for system balancing and security of supply. As the revenues available to coal power plants decrease, closure of unprofitable plants could reduce dispatchable capacity, potentially threatening security of supply. At the same time, stronger operational flexibility is needed across the power system, with flexible generators needing to ramp up and down more quickly to accommodate variations in the supply of renewable generation.

The current policy of capacity payments to coal plants addresses the first of these problems, but has significant drawbacks. It risks overpayment, as well as over-investment in coal plants beyond the level of capacity that is actually needed. Unless other measures are introduced to drive coal out of the generation mix, these payments may lead to coal plants increasing their generation by bidding lower than their marginal cost in MLT markets, impeding the shift of coal plants to a more genuine back-up role. This approach risks promoting lock-in to incumbent technologies, rather than supporting new technologies to provide security, such as mid- or longer duration energy storage, and demand side response that could be beneficial for system flexibility as well as for reducing both costs and emissions.

Since 2014, the UK has used a capacity market in which existing and new-build power plants compete in auctions for contracts that provide fixed payments in return for being able to generate when called upon by the system operator during periods of system stress. This has achieved required levels of capacity availability with far lower procurement of new plants than was expected, and at lower-than-expected costs (below £20/kW/year for the first seven delivery years, compared to an expected £50/kW/year). This success has been due in part to the capacity market supporting a more diverse range of technologies than expected. While most contracts have been awarded to existing gas plants, contracts have also been won by nuclear plants, interconnectors, batteries, and demand side response. In recent years, most of the new-build capacity procured has come from battery energy storage systems.

The UK now faces the challenge of aligning the capacity market with the goal of achieving a fully zero emission power system over the next 5-10 years. The government is considering creating separate 'windows' within capacity market auctions—with different clearing prices and minimum procurement targets—for high- and low-emissions technologies, or for technologies with different operating characteristics, such as response time, duration, and location in the context of transmission constraints and interconnector availability. Other options under consideration include an emissions limit within the capacity market, and additional support for the conversion of gas plants to hydrogen-to-power or power with carbon capture and storage.

In China, replacing coal capacity payments with a capacity market could reduce risks of overpayment and over-investment, and support the deployment of technologies that contribute more to system flexibility. Since the extent to which new technologies could compete successfully against coal plants in a single undifferentiated capacity market is unclear, an option could be to create separate auction windows with one for established technologies, including coal, gas, and pumped hydro, and others for flexible technologies such as energy storage, demand side response, and virtual power plants. The capacity value of battery storage could be expressed through a de-rating factor reflecting provincial context as well as storage duration.

Taking full advantage of the opportunities of energy storage

Energy storage systems, including battery energy storage systems (BESS), enhance security of supply through their ability to respond quickly to system stress events. They also support system stability by providing frequency control services. In addition, storage technologies of varying durations can capture surplus variable renewable energy (VRE) that would otherwise be curtailed and shift it to times of higher demand, guided by fluctuations in wholesale electricity prices (i.e. through arbitrage). A reinforcing feedback between renewable deployment increasing the arbitrage opportunities for BESS, and BESS deployment increasing the opportunity for profitable generation of renewable power, could be a powerful dynamic driving progress towards a power system that is carbon neutral, low-cost, and secure.

The energy storage mandate implemented in China since 2017 and abolished by *Document 136* had an ambiguous effect on the reinforcing feedback between deployment of renewables and deployment of storage, because BESS assets were underutilised (the utilisation rate averaged just 9% in 2023) and at the same time it increased costs for renewables (by up to 10% for solar, and up to 20% for wind). Greater utilisation of BESS could be achieved by advancing the development of spot markets and loosening spot price floors and caps (increasing arbitrage opportunities), continuing development of competitive ancillary service markets with fair access and participation criteria, and including BESS in capacity remuneration mechanisms. The costs of energy storage could be met more efficiently by sharing them among all users of the system, reflecting the system-level benefits of storage, instead of allocating them only to renewable generators.

Long-duration energy storage (LDES) is expected to be important in a fully decarbonised power system, and could be valuable in the nearer term for utilising surplus renewable supply. Multiple technologies exist for LDES, at varied stages of development. Substantial policy support is likely to be needed for deployment, given that capital costs remain high, frequency of utilisation may be low, and initial deployment is necessary to test, demonstrate, and improve performance.

The UK government has recently proposed a revenue cap-and-floor policy to support investment in LDES by reducing revenue uncertainty. This follows the UK's successful use of a revenue cap-and-floor policy to enable investment in interconnectors: under this policy, interconnector capacity has nearly tripled, while top-up payments to meet the revenue floor have never been required. In China, there is a need to complement the many LDES technology demonstration projects under way with an effective deployment policy. The package of policies being piloted in Shandong, including dedicated capacity payments, could be transformative if implemented on a national scale.

Managing the declining role of coal power

Thermal power plants' share of China's power generation has fallen from 73.7% in 2015 to 63.2% in 2024, and this decline is set to continue. Meanwhile, construction of nearly 95 GW of new coal plant capacity began in 2024. The challenge for policy is to manage the declining role of coal power cost effectively, maintaining enough to ensure security of supply while avoiding unnecessary investment in excess capacity.

The national emissions trading system (ETS) has contributed to increasing the efficiency of the coal fleet, but its effectiveness is limited by a dampening feedback. Any substitution of inefficient coal plants with other forms of generation tends to decrease net demand for emissions allowances, reducing their price and reducing the incentive for further substitution. The low carbon price that emerges (typically below ¥100/tCO_2, or €13 /tCO_2, so far), combined with the net subsidy that the ETS pays to more efficient coal plants, means that at present the ETS provides little safeguard against unnecessary investment.

A hard cap on emissions could prevent overinvestment, but setting a stringent emission reduction trajectory for the cap would be difficult given growing electricity demand and uncertainty over the pace at which new technologies can replace coal in ensuring security of supply. A weak cap, on its own, could be inconsistent with China's emission objectives and lead to very low ETS prices. To complement an emissions cap, a carbon price floor could limit this dampening feedback within the ETS and allow it to remove the least efficient coal plants from the system. The level of the floor price could be amended annually to respond to any over- or under-achievement.

Retaining some coal plants in a strategic reserve instead of fully retiring them could give provincial governments increased confidence in security of supply, reducing the risk of overinvestment in thermal power capacity and allowing a strengthened ETS to remove coal plants from the system as they cease to be needed. By taking backup plants out of the market, it could also create more space for the growth of flexibility technologies.

Systemic interactions between power sector policies and market reforms

Almost all power sector policies involve some degree of trade-off between the energy trilemma objectives of reducing costs, cutting carbon emissions, and ensuring security of supply, even though the falling cost of renewables means the long-term objectives of low costs and low emissions are increasingly closely aligned. Two forms of intervention stand out for their potential to have positive effects across all three trilemma objectives, provided their costs are managed carefully: policies to increase the deployment of energy storage, with costs borne at the system level; and policies to enable cross-provincial electricity trading. Both increase the system's flexibility and its ability to absorb large volumes of low-cost variable renewable power.

The effect of the market liberalisation process on the trilemma objectives is highly uncertain and contingent on many factors. To ensure it leads to lower prices and lower emissions, it will be important to adopt contracting structures for renewables that break or limit the dampening feedbacks described above. To achieve a positive effect on security of supply, measures will be needed to ensure the full market participation of energy storage and demand-side response. A helpful reinforcing feedback between growth in the profitability and deployment of renewables and decline in coal power's share of generation could be activated, if the gradual removal of guaranteed purchase contracts for coal plants is accompanied by a loosening of price controls. Allowing market prices to vary by location both within and across provinces can bring into play several feedbacks that could contribute to lower prices by managing geographical imbalances.

The most significant mutually offsetting relationship between current policies is that between the coal capacity payments and the ETS. Creating a capacity market in which carbon intensity or energy efficiency are criteria in the allocation of capacity payments to coal plants could transform the relationship with the ETS from offsetting to synergistic. The feedback within the ETS also introduces an offsetting effect in its relationship with any other policies that move the transition forward. As the ETS is extended beyond the power sector, sector-specific carbon floor prices could be used to limit this effect, so that progress in the transition in one sector does not weaken the incentive for progress in another.

In some cases, a policy's direct effect on power system costs, emissions, or security of supply is directionally opposite to the effect that it may indirectly have on the same variable, when the feedbacks in the system are considered. This reflects the difference between marginal change and structural change, and underlines the need for dynamic analysis in the context of the power sector's technology transition.

Introduction

The transition to new technologies in the power system is changing the nature of the system itself. Variations in electricity supply are becoming as significant as variations in demand. Costs are dominated by the capital required for new assets, instead of by fuel for their operation. Generation is increasingly dispersed instead of centralised, and benefits from economies of location more than economies of scale. Transmission is no longer one-way, from generators to consumers, but works in different directions at different times. The changes under way are deep and structural.

The opportunity for mutual learning between China and the UK

Both China and the UK can claim leadership in this transition. China's investment in solar and wind power is far ahead of any other country: in 2023, China was responsible for 63% of global solar PV additions and 65% of new wind capacity.[1] The UK achieved a faster rate of power sector decarbonisation than any other large country over the decade 2008 to 2017,[2] and was the first country to deploy offshore wind power at scale.

The two countries approach the transition on different scales and from different starting points. Measured in terms of generation capacity, China's power system is about 30-40 times larger than that of the UK. China's ongoing process of reform is moving from a highly state-controlled power system to an increasingly liberalised market-oriented system. Meanwhile, the UK's power system, which was one of the first in the world to be liberalised, is now increasingly being re-shaped to adapt to the transition.

Despite these differences, the two countries are now facing a similar set of challenges. How will they maintain rapid growth in clean energy investment, in a system where revenues are increasingly uncertain? How might

[1] Rangelova, K. (2024). 2023's record solar surge explained in six charts. Ember Energy. Available at: https://ember-energy.org/latest-insights/2023s-record-solar-surge-explained-in-six-charts/

[2] Staffell, I., Jansen, M., Chase, A., Cotton, E., and Lewis, C., 2018. Energy revolution: a global outlook.

they ensure energy storage and other flexible technologies are deployed and used in a way that contributes to security of supply? How should locational disparities in supply and demand be managed? How can market design ensure that the low cost of renewable power generation is converted into low prices for consumers?

Many of these challenges are closely related to the rising share of variable renewable energy (VRE) in electricity generation.[3] Although this share is higher in the UK than in China, in recent years it has been increasing at a similar rate in both countries, as shown in Figure I-1, and in some Chinese provinces it is already higher than in the UK.

These similarities in the challenges faced mean that there are opportunities for policymakers in China and the UK to learn from each other's ideas and experiences as they pursue their respective power sector reform processes. The UK aims to reduce power system costs substantially and maintain a high level of security of supply while reaching a 95% share of zero emission sources in power generation by the year 2030. To meet these objectives, the government's Review of Electricity Market Arrangements (REMA) programme is considering options for changes to all aspects of the system (see Figure I-2). China's policymakers face some similar choices as they work towards the objectives of reaching peak carbon emissions and establishing a unified national electricity market system by 2030.

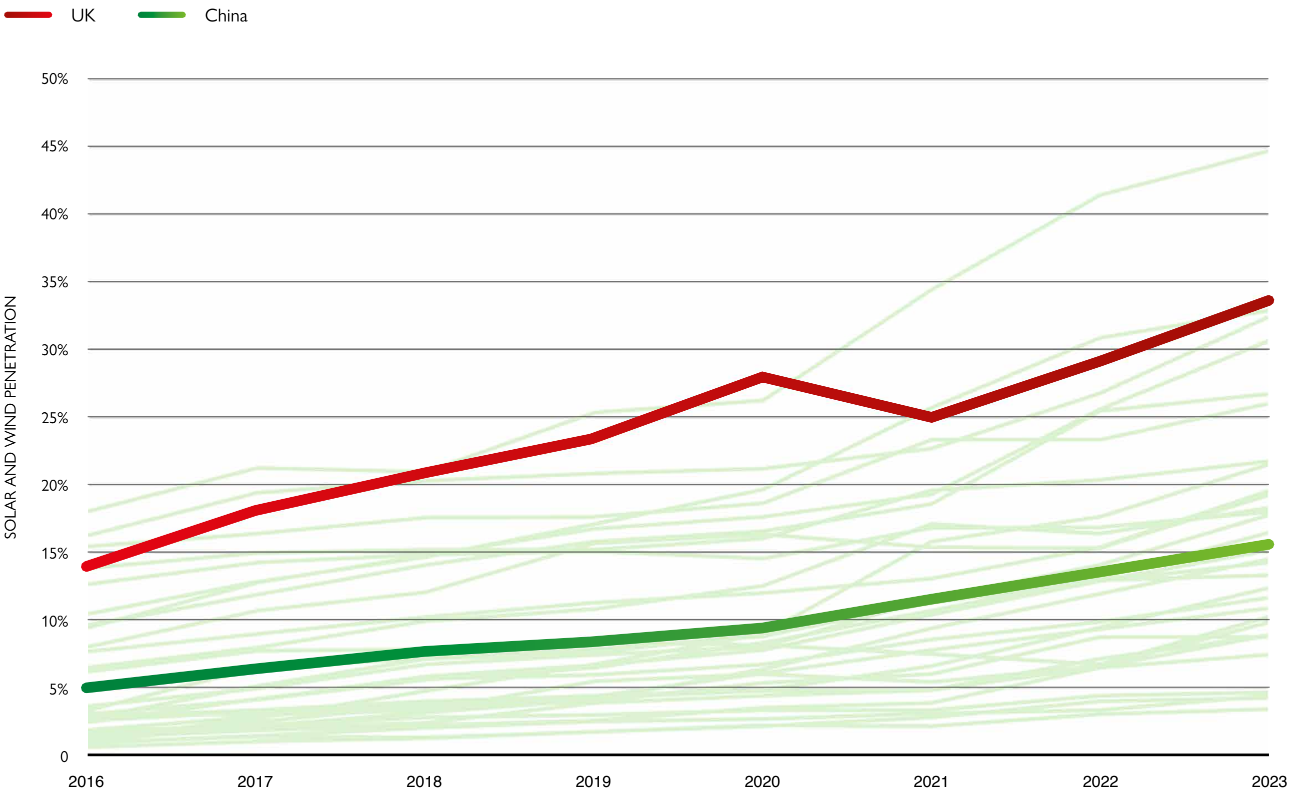
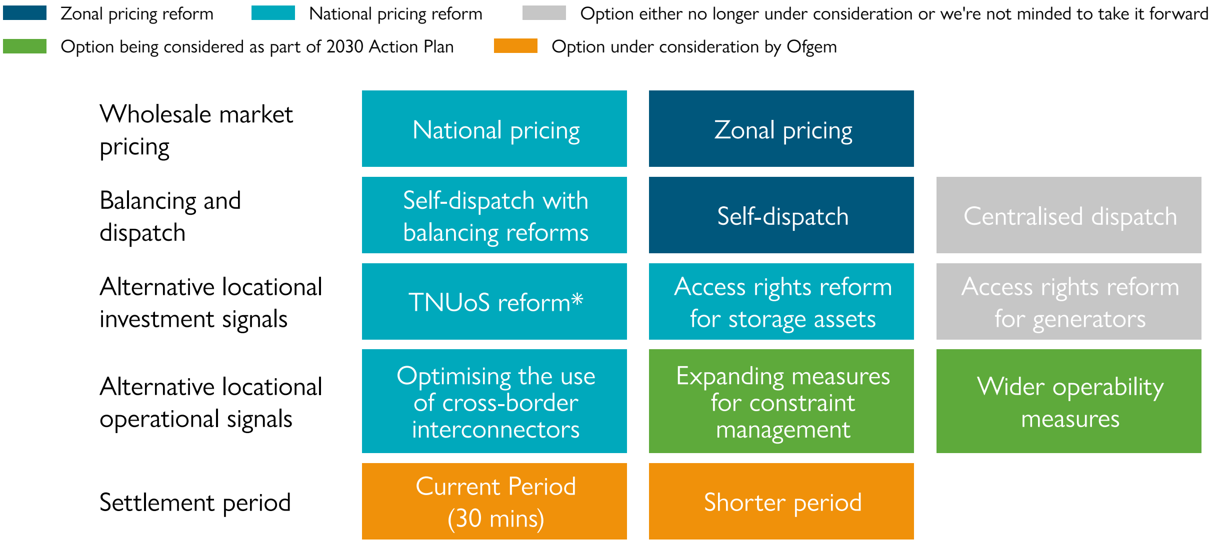


Figure I-1: Solar and wind share of power generation in China and the UK over 2016-23.
Note: Red line represents UK national data, green line represents Chinese national data, light green lines represent data for 31 province-level jurisdictions in China. Source: Data collated by RMI.[4]

[3] IEA, 2024. Integrating Solar and Wind. Available at: https://www.iea.org/reports/integrating-solar-and-wind

[4] Walter, D., Bond, K., & Butler-Sloss, S. (2024). Inside the Race to the Top: The race for cleantech among Chinese provinces, US states, and European countries. RMI. https://rmi.org/wp-content/uploads/dlm_uploads/2024/12/Inside_the_race_to_the_top-1.pdf



* We would also need to consider the role and design of TNUoS in a zonal market

Figure I-2: Some of the market reform options under consideration in the UK government's Review of Electricity Market Arrangements programme, as of the Autumn update in December 2024.[5]
Note: The UK government's views on these options continue to evolve. The options under consideration as of the Autumn Update represent a selection of a larger range of options considered in earlier stages of the review; many choices have already been discounted. For more detail on these, see previous consultation documents.[6]

Analytical challenges in policy appraisal

The practical challenges of the power sector transition present methodological challenges for policy appraisal. As change is structural, not marginal, cause and effect can often be disproportionate. This can lead to good surprises—with policies such as subsidies for solar and wind power resulting in far greater levels of deployment than originally anticipated, in many countries—but also to difficulties, such as the costs of those subsidies being higher than anticipated, or other policies achieving less than expected. Since many of the outcomes of structural change are uncertain, it can be impossible to compare policy options by precisely calculating costs and benefits; instead, they must be weighed in terms of risks and opportunities.[7]

Adding to the difficulty is the fact that, as an increasing number of policies are required to adapt the power system to its new technologies, the effect of any one policy is not independent of the others. The outcomes that governments tend to be most interested in—the cost of electricity, security of supply, and carbon emissions—are characteristics of the whole system, and arise from the interactions between policies, market reforms, and technological change. Understanding these interactions becomes a high priority for analysis.

An important distinction in policy and analysis is between two forms of economic efficiency: allocative efficiency and dynamic efficiency. Allocative efficiency involves making the best use of a given set of economic resources, while dynamic efficiency is concerned with the creation of new resources and structures through processes of innovation, investment and growth.[8]

In its work on the REMA programme, the UK government has recognised the different roles of markets in relation

[5] UK Department of Energy Security & Net Zero. (2024). Review of Electricity Market Arrangements: Autumn Update (Review of Electricity Market Arrangements). https://assets.publishing.service.gov.uk/media/675acc977e419d6e07ce2bc3/rema-autumn-update.pdf
[6] Department of Energy Security and Net Zero. (2024). Review of Electricity Market Arrangements: Second Consultation Document.
[7] Grubb, M. et al, 2021. The new economics of innovation and transition: evaluating opportunities and risks. Available at: https://eeist.co.uk/eeist-reports/
[8] Kattel, R. et al, 2018. The economics of change: policy and appraisal for missions, market shaping and public purpose. Available at: https://www.ucl.ac.uk/bartlett/public-purpose/sites/public-purpose/files/iipp-wp-2018-06_1.pdf

to these distinct forms of economic efficiency.[9] Markets typically achieve allocative efficiency through pricing mechanisms, allowing assets to be put to their most highly valued uses. Policy can support this by removing constraints, increasing information, and enabling prices to vary to reflect any relevant factors (for example, in electricity markets, varying by time-of-day and by location). Markets contribute to dynamic efficiency when they incentivise innovation and technological progress. Policy can enable this by encouraging investment in low-carbon technologies, by ensuring that the market rewards investment in these technologies more than investment in polluting assets, and by adapting regulatory structures and other properties of the system (such as infrastructure) to allow the market share of the low-carbon technologies to continue to grow.

When allocative efficiency is the primary concern, policy options can often be assessed using cost-benefit analysis—a static technique (in the sense that the outcomes of a policy are considered at fixed moments in time). When dynamic efficiency is of interest, different approaches are needed; it becomes necessary to consider how policies will affect processes that drive change in the economy over time.

Systems mapping to analyse dynamic efficiency and policy interactions

Systems mapping with causal loop diagrams (CLDs) is an analytical technique that can be useful for considering the dynamic efficiency of policy options.[10] It is centred on the identification of feedback loops between the variables in a system. There are two kinds of feedback loop: reinforcing feedbacks, in which an increase in one variable leads to a further increase in the same variable, tending to amplify impact or accelerate change; and dampening feedbacks, in which an increase in one variable leads to a decrease in the same variable, tending to limit change or preserve stability. The behaviour of a system depends on these feedbacks and the interactions between them.

Reinforcing feedbacks are often present in the development and diffusion of new technologies. When investment in a new technology increases, this may lead to improvements in its performance and reductions in its cost, tending to increase demand for this technology in the market, incentivising further investment. Dampening feedbacks are often present in commodity markets: an increase in supply of a commodity tends to reduce its price (if demand is constant), and the lower price reduces the incentives for further supply.

The system maps in this report represent relationships and feedbacks with the following notation. A green arrow indicates that when one variable moves in a certain direction (increase or decrease), it causes the next variable to move in the same direction. A red arrow indicates that one variable causes the next variable to move in the opposite direction. The letter “R” indicates a reinforcing feedback loop arising from a set of relationships between variables, and the letter “D” indicates a dampening feedback loop. Figure I-3 illustrates this notation applied to the two examples of feedbacks mentioned above.

Policies can create, break, strengthen or weaken such feedbacks. If these dynamic effects are anticipated, policymakers can design interventions to be self-amplifying in a desired direction, and not self-limiting, or to ensure system stability rather than instability. Understanding feedbacks can be useful for identifying opportunities and reducing the risks of unwelcome surprises.

Since this analytical technique is focussed on the interactions between variables in a system, it can also be useful for assessing the likely effects of interactions between policies. In the context of technological change in the power sector, it can contribute to an understanding of which policies and market reforms may be mutually reinforcing, and which may conflict with one another. This is one of several analytical techniques that have been used by UK government analysts to consider policy options as part of the REMA programme.[11]

[9] UK Department for Energy Security and Net Zero, 2024. Review of Electricity Market Arrangements: second consultation document, p20. Available at: https://www.gov.uk/government/consultations/review-of-electricity-market-arrangements-rema-second-consultation

[10] Meadows, D., 2008. Thinking in systems: a primer.

[11] UK Department for Energy Security and Net Zero, 2024. Review of Electricity Market Arrangements: Options assessment, p111. Available at: https://www.gov.uk/government/consultations/review-of-electricity-market-arrangements-rema-second-consultation

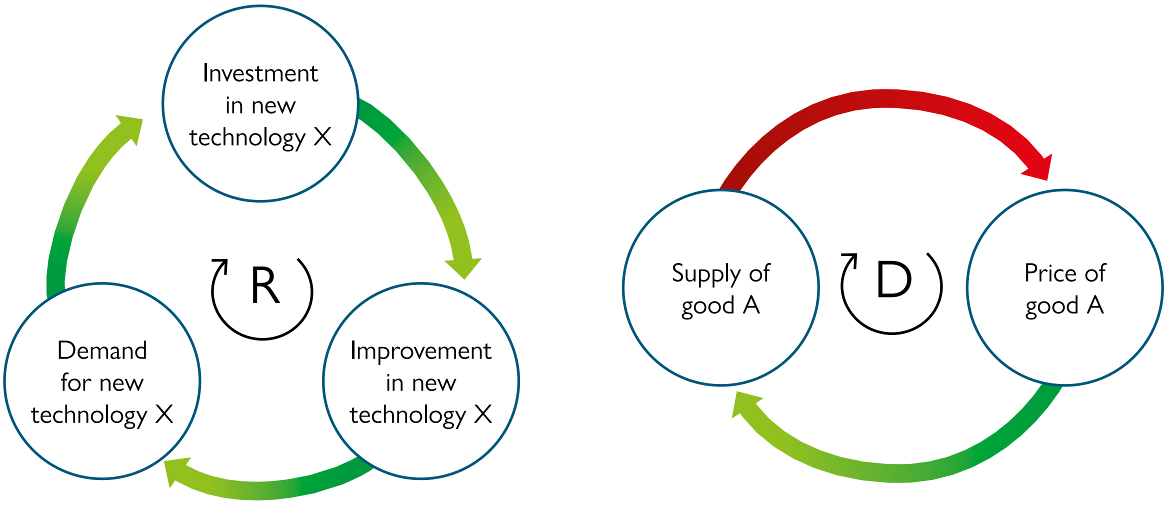


Figure I-3: Illustration of causal loop diagram notation applied to: (a) a reinforcing feedback related to investment, improvement, and demand for a new technology (left); and (b) a dampening feedback between supply and price in a commodity market (right). The letters "R" and "D" denote reinforcing and dampening feedback loops, respectively.

Purpose and structure of this report

This report, by a joint China–UK research team, aims to contribute to the understanding of opportunities and risks for power sector reform in China in two ways: firstly, by considering the potential relevance to China of market reform options implemented or considered in the UK; and secondly, by using systems mapping with CLDs to assess the dynamic efficiency of policy options and the interactions between different policies and market reforms.

The first two chapters focus on policy problems. In Chapter 1, we focus on the challenge of how to maintain growth in investment in renewable power, in the context of a rising share of VRE in power generation, and a liberalising electricity market. In Chapter 2, we focus on how to ensure security of supply in the context of technological change, and how to manage the declining role of thermal power generation technologies.

The next two chapters focus on analytical methods. Chapter 3 uses systems mapping to look more broadly at interactions between policies and markets across the power system, identifying further feedbacks, and areas of synergy and conflict between different policies in relation to the goals of keeping costs low, ensuring security of supply, and reducing carbon emissions. In Chapter 4, we review the extent to which existing quantitative models are able to inform the policy options discussed in the first two chapters, and suggest priorities for model development.

This report is a product of the Economics of Energy Innovation and System Transition project, a collaborative programme in which researchers from China and the UK are working to advance understanding of the decision-making frameworks, economic models, and principles of policymaking that are most appropriate to the context of the energy transition.[12]

[12] Grubb, M. et al, 2024. Economics of Energy Investment and System Transition: Synthesis Report. Available at: https://eeist.co.uk/eeist-reports/

Chapter 1
Sustaining rapid growth of renewable power in the context of market liberalisation

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Contents

1. Context

1.1 Renewables in China and the challenge of sustaining investment

The growth in deployment of renewable power technologies has far exceeded expectations.

By the year 2020, total global deployment of solar photovoltaics (PV) was more than ten times the level implied by the targets that governments had set for that year, fifteen years previously (Beinhocker, Farmer and Hepburn, 2022). Nowhere has the outperformance of targets been as great as in China. In 2008, the Chinese government set a target of deploying 1.8 GW of solar power by 2020. When the year 2020 arrived, solar deployment in China stood at 252 GW; the capacity of renewables has almost doubled since then.

This non-linear progress has been driven by the amplifying feedbacks of technology deployment and diffusion. Rapid growth in production and deployment of solar and wind technologies has led to reductions in their costs (understood as LCOE—levelised cost of energy). These cost reductions are driven by several mechanisms:

1. **Learning-by-doing**—as cumulative production and deployment grows, improvements in manufacturing and project development lead to lower costs.
2. **Economies of scale**—as production is scaled up, unit costs decrease, typically through both direct scale economies in factories and through enhanced supply chains.
3. **Network effects and emergence of complementary technologies**—as adoption increases, synergistic relationships form between the technology, users, institutions, and complementary technologies.

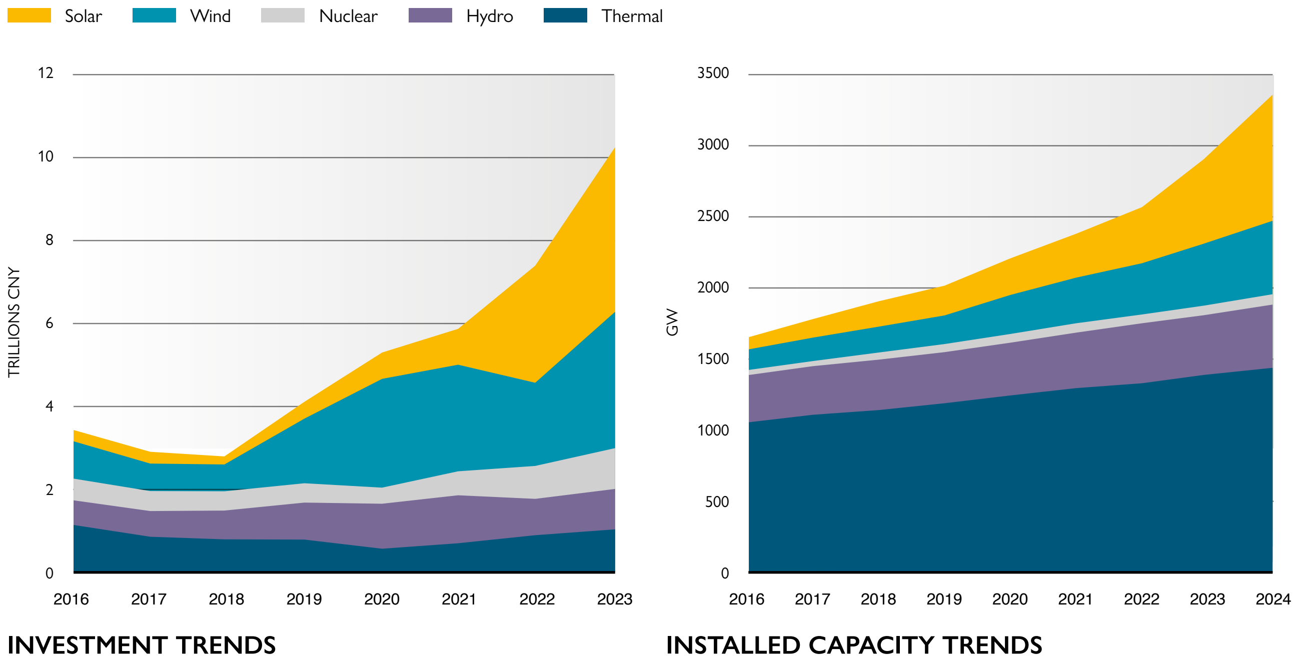

Figure 1-1: Trends in Chinese power generation investment and installed capacity by technology. Note: Investment trends are shown on the left-hand axes, and installed capacity trends are on the right-hand axes. Data are from 2016-2024.[1]

Improved performance and lower costs then lead to increased demand and profitability (assuming cost reductions are not competed away), which prompts further investment and deployment (Figure 1-2).

This reinforcing feedback (Figure 1-2) is central to the transition to clean power. Keeping it operating is essential for meeting the policy goals of carbon peaking and carbon neutrality in the power sector, and for keeping electricity costs low for consumers.

The conditions that have supported the rapid growth of renewables in China's power sector are changing. Previously, VRE enjoyed guaranteed full purchase with fixed prices, backed by the 2009 amendment to China's *Renewable Energy Law*.[2] However, rapid growth in deployment, supported by feed-in tariff policies, has ushered in new issues of VRE integration and large subsidy burdens. To address the latter issue, subsidised feed-in tariffs were gradually wound back through the 2010s in line with VRE technology cost reductions, before being phased out altogether in 2021 (Table 1-1).[3] Now, reform efforts are firmly set on establishing a "unified national power market system" by 2030 to promote efficiency and enable ongoing market-based integration of VRE.[4] To this end, requirements that renewable power be sold via market channels are growing stricter by the year, with the proportion of output covered by purchase guarantees[5] being wound back accordingly.

In the post-subsidy era, and as part of the long-term process of market liberalisation, market reforms are increasingly exposing renewables to competition. A 2029 deadline has been set for full market participation, per a 2024 blue book prepared by the China Electricity Council (CEC) for the National Energy Administration (NEA).[11] The proportion of variable renewable energy (VRE) sold via market channels has risen rapidly in the post-subsidy era to 47.3% of total VRE output in 2023,[12] driven by provincial policies phasing out VRE guaranteed purchase in favour of market entry (see Table 1-2). This follows the broader trend of market expansion across the system's supply side (see Figure 1-3).

1 Data: Wang and Cui (2024). China electricity development and reform report (2024). China Energy Media Research Institute.
2 See Article 14 of the 2009 amendment to Renewable Energy Law, available in English.
3 We acknowledge that the publication of *Document 136* has altered some of these dynamics, but this will be addressed later in the document.
4 NDRC and NEA (2022). Guiding opinions on accelerating construction of a unified national electricity market system. 发改体改 [2022]118号
5 Chinese regulators provide VRE generators with purchase guarantees whereby a certain proportion of their output will be purchased at a fixed price, usually set at the coal-fired benchmark price in the post-subsidy era (after 2021).

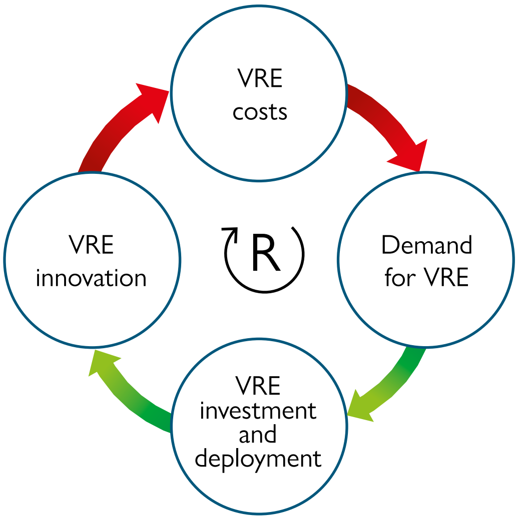

Figure 1-2: CLD of the learning-by-doing feedback loop between VRE costs and deployment.
Note: VRE costs is understood as the LCOE (levelised cost of energy) for VRE. Green arrows indicate a positive relationship (i.e. factors move in the same direction) and red arrows indicate a negative relationship (i.e. factors move in opposite directions). The letter "R" denotes a reinforcing feedback loop.

Table 1-1: Fixed prices of onshore wind and solar power from 2009-21
Note: "Resource area type" refers to zoning categories assigned based on VRE resource abundance, with zone I experiencing the best VRE resources, and zone IV experiencing relatively poorer conditions.

	Resource area type	2009[6]	2013[7]	2015[8]	2018[9]	2019[10]	2020	After 2021
Onshore wind (¥/kWh)	I	0.51	0.51	0.49	0.4	0.34	0.29	Coal-fired power benchmark price
	II	0.54	0.54	0.52	0.45	0.39	0.34	
	III	0.58	0.58	0.56	0.49	0.43	0.38	
	IV	0.61	0.61	0.61	0.57	0.52	0.47	
Solar (¥/kWh)	I	n/a	0.9	0.9	0.5	0.4	0.35	
	II	n/a	0.95	0.95	0.6	0.45	0.4	
	III	n/a	1	1	0.7	0.55	0.49	

6 See NDRC (2009). Notice on improving wind power on-grid pricing policies. 发改价格[2009]1906号
7 See NDRC (2013). Notice on giving full play to the role of price levers to promote the healthy development of the PV industry. 发改价格[2013]1638号.
8 See NDRC (2015). Notice on appropriately adjusting benchmark on-grid prices for onshore wind power. 发改价格[2014]3008号
9 See NDRC (2016). Notice on adjusting benchmark on-grid prices for solar PV and wind power. 发改价格[2016]2729号. See also NDRC, MoF and NEA (2018). Notice on matters related to solar PV power in 2018. 发改能源[2018]823号.
10 For 2019 and 2020 data, see NDRC (2019). Notice on improving wind power on-grid pricing policies. 发改价格[2019]882号; NDRC (2019). Notice on issues related to improving solar PV on-grid price mechanisms. 发改价格[2019]761号; and NDRC (2020). Notice on matters related to 2020 solar PV on-grid price policies. 发改价格[2020]511号

These shifts imply changes to the size of different components of the power market system. For the generation side, all thermal power is integrated into market trading, while VRE is partially sold through guaranteed purchase policies, with the remaining portion participating in the market. On the consumer side, when purchasing electricity, not only do users bear the on-grid electricity prices of generators, but they also incur costs for transmission and distribution, line losses, system operation, as well as government funds and other expenses (see Figure 1-4). Currently, residential and agricultural users continue to follow fixed electricity prices set by the government,[15] while industrial and commercial users have the option to directly participate in market trading or engage in transactions through grid proxy services[16].

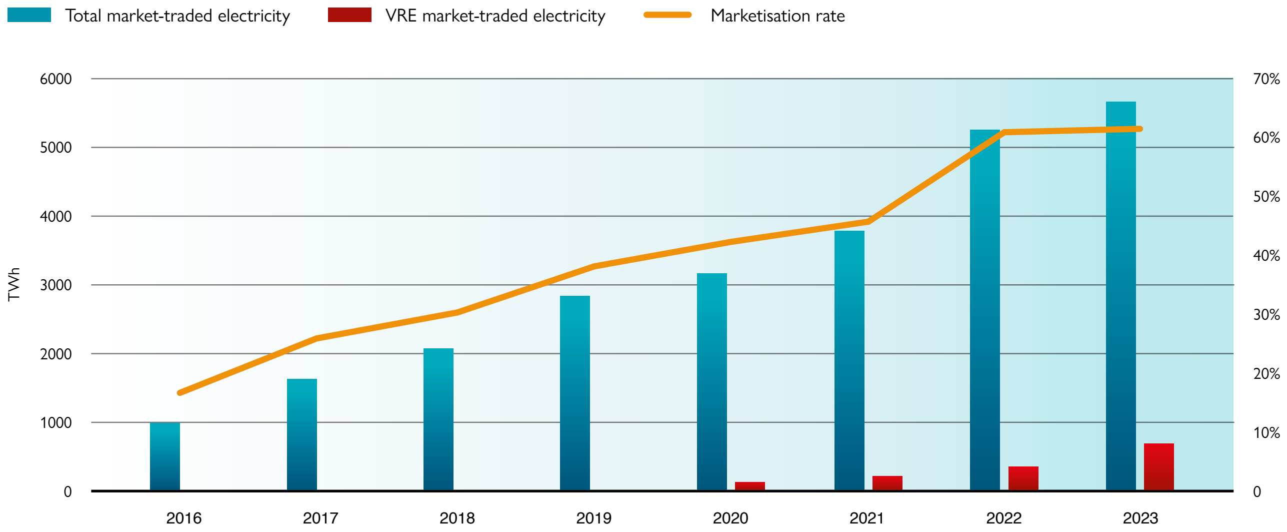

Figure 1-3: Trends in market trading of electricity.
Note: Quantities of market-traded VRE electricity[13] are shown in red, and that of electricity from all sources[14] in blue. The orange line (marketisation rate) depicts the proportion of all power that is sold via market-oriented channels.

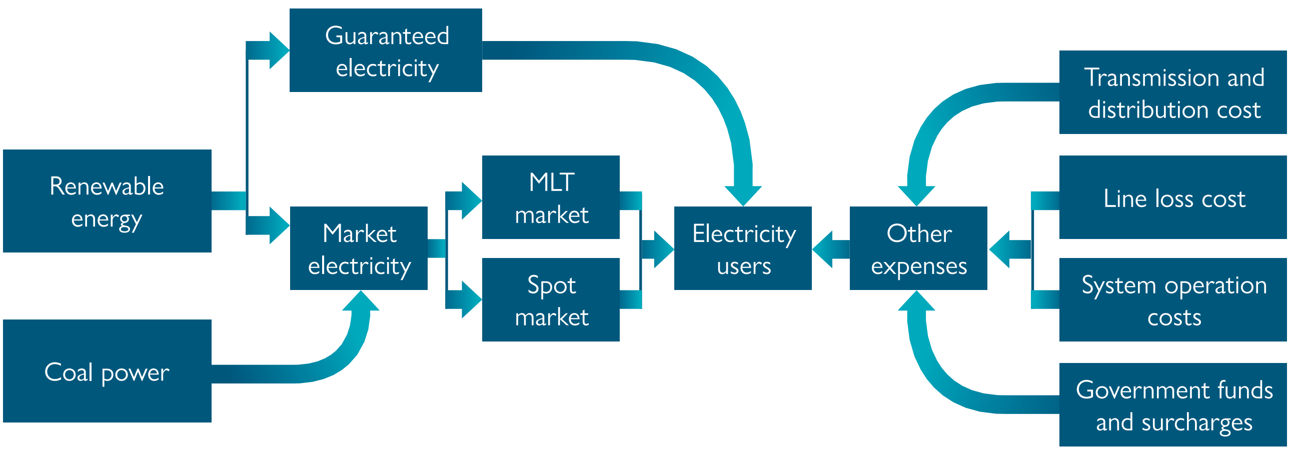

Figure 1-4: Chinese electricity market structure.

[11] See NEA reports.
[12] Per NEA statistics.
[13] Data from 2023 China electricity market trends and outlook.
[14] Data from CEC (2024). Blue book on the development plan for a unified national electricity market.
[15] Power tariffs for residential and agricultural users are set by provincial governments in line with pricing frameworks developed by NDRC.
[16] "Grid proxy services" (电网企业代理购电) refers to the practice of grid companies purchasing electricity through market transactions on behalf of commercial and industrial users that do not directly participate in market trading.

Table 1-2: VRE market participation requirements[17]
Note: Data is from selected provinces and current as of early 2025. Note that the right-hand column shows the scale of power generation currently covered by guaranteed purchase, but in some provinces (e.g. Zhejiang), this is implemented via government-authorised contracts (see Section 1.4.2). In the future, this proportion of generation will likely switch from being covered by guaranteed purchase to being covered by CfDs, based on new policy in *Document 136* (See Section 1.4.3).

Province	Requirements for utility-scale VRE to participate in power markets		Generation hours/proportion covered by guaranteed purchase	
			Wind	Solar
Inner Mongolia	West	Must sell non-guaranteed power via market	390	320
	East		790	635
Shandong	Generators can choose to either sell all their power via market (i.e. 0% guaranteed), or sell only non-guaranteed power		70% or 0%	85% or 0%
Heilongjiang	Must sell non-guaranteed power via market		700	450
Zhejiang	Must sell non-guaranteed power on spot market		90%	
Xinjiang	Must sell non-guaranteed power via market		895	500
Hebei (south)	Must sell non-guaranteed power via market		70%	40%

1.2. Report context and goals

Both China and the UK have achieved strong levels of VRE deployment to date despite their vastly different institutional and market arrangements. It is worth discussing these differences briefly to frame the analysis presented in this chapter.

Investment in generation capacity (including VRE) in the UK power system, which was liberalised in the 1990s (see Section 2.1), is dominated by the private sector. As such, investment decisions and the cost of capital have proven to be sensitive to various risks related to future revenues.

In China, however, a significant proportion of VRE investment is undertaken by state-owned enterprises (SOEs). In 2023, six Chinese central SOEs were responsible for roughly 40% of all new VRE capacity growth in that year;[18] this figure excludes capacity built by local SOEs or smaller central SOEs, meaning the true proportion of state-owned assets is likely to be significantly higher than this. This is a fundamental difference between the two countries, as the state-led model in China gives more traction to political signals, often expressed through policy requirements, as key drivers of investment. For example, in 2021, SASAC (State-owned Assets Supervision and Administration Commission of the State Council) introduced a requirement for all central power SOEs to increase the proportion of VRE capacity in their investment portfolios.[19] State ownership allows developers to tolerate lower profits than private investors. Moreover, the Chinese financial ecosystem provides low-interest loans to VRE investors via green finance initiatives implemented by state-backed banks, reducing the cost of capital.[20] As such, political signals play a defining role in driving and enabling VRE investment in China.

[17] Data from Jingxin Solar (2024). 2025 Overview of new energy market entry policies in twelve provinces.
[18] Data from STCN (2024). Selling off wind and solar assets en masse—are central state-owned enterprises really shrinking new energy?
[19] See SASAC (2021). Guiding opinions on advancing the high-quality development of central SOEs' carbon peaking and carbon neutrality work. 国资发科创[2021]93号
[20] See State Council (2021). People's Bank of China rolls out carbon emissions reduction support instrument.

However, this does not mean that Chinese VRE investment is immune to risk or profitability concerns. Representatives of SOEs interviewed by researchers in this project have described their organisations' investment decisions as responding to both political signals and market conditions. SOEs must demonstrate their profitability to the regulator (SASAC), so while they may be able to tolerate loss-making activities to meet political objectives over a short period of time, this may not be sustainable in the long term. In practice, SOEs' VRE investments must also meet a certain projected internal rate of return threshold to be approved internally. Furthermore, policymakers have indicated that market signals will play a stronger role in guiding investment decisions in the future.[21]

Therefore, notwithstanding the differences between the two countries, there is a growing scale of common challenges to sustaining the pace of renewables growth. The UK by no means offers definitive solutions, particularly given its ongoing struggles with high consumer bills, but its relative success in rapidly decarbonising the power sector in a liberalised system could offer valuable lessons for the Chinese context.

In the UK, the success of its market reforms in the early 2010s has resulted in a situation with VRE now accounting for over a third of electricity generation, and questions are emerging about how growing periods of surplus generation may impact both market operation and investment.

In China, the two trends of market liberalisation and growing VRE penetration could converge to undermine investment in renewables in future, particularly in provinces where penetration is reaching a similar share to that in the UK.

This challenge is VRE cannibalisation—the phenomenon whereby, as VRE penetration rises in a liberalised market, dampening feedbacks emerge which can start to deter investment. This is an important challenge to ongoing investment in both the UK and China, and is illustrated schematically in Figure 1-5.

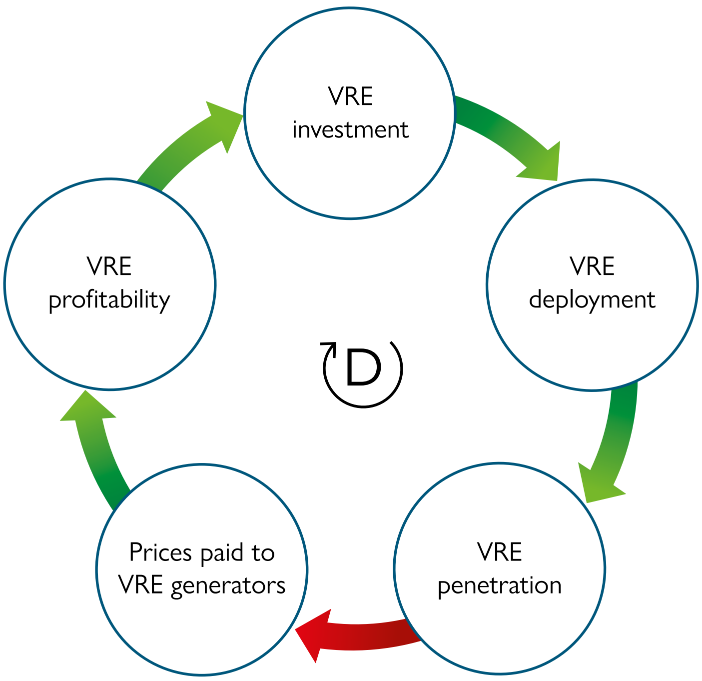

Figure 1-5: CLD showing cannibalisation effects on VRE development.
Note: Green arrows indicate a positive relationship (i.e. factors move in the same direction) and red arrows indicate a negative relationship (i.e. factors move in opposite directions). The letter "D" denotes a dampening feedback loop.

[21] See NDRC and NEA (2022). Guiding opinions on accelerating the construction of a national unified electricity market system. 发改体改[2022]118号。

2. Policies for renewables investment in a competitive electricity market: the UK experience and Contracts-for-Difference (CfDs)

Comparison of the Chinese and UK experiencces with renewable energy must acknowledge one stark difference. The UK undertook radical liberalisation of its electricity system in 1990, when the system was dominated by coal and nuclear generation, but wind and solar then were essentially irrelevant and barely considered. The policy challenge was to support renewable energy growth in the context of a competitive wholesale market. In contrast, the liberalisation process in China is proceeding more cautiously, and in parallel with the expansion of VRE as a major and rapidly growing source of electricity.

This section summarises essential features of the UK journey with reference to renewable energy investment, culminating with the rationale for and experience of CfDs. The subsequent sections explain the joint challenges facing both countries and options to sustain the growth of renewables investment.

2.1 The first 20 years, 1990 – 2010

When the UK first liberalised its electricity system in 1990—both selling state-owned assets, and injecting competition—a dominant question was around operation and financing of nuclear power. The government introduced the Non-Fossil Fuel Obligation (NFFO), which obliged electricity suppliers (i.e. companies selling to final consumers) to procure a certain percentage of electricity from non-fossil sources. While primarily designed to ensure the economic viability of nuclear generators, 5% of the funds in the NFFO were set aside to support renewable generation (Douglas and Saluja, 1995).

As attention turned to renewables, there were five bidding rounds for capacity, procured through a central Non-Fossil Purchasing Agency, which awarded contracts to the cheapest bidders for (mainly) 20-year fixed price contracts. The additional costs - both of renewables, and the nuclear fleet - were paid for by a levy on electricity consumers. Whilst the NFFO succeeded in getting renewables launched, it suffered from the "winner's curse" of largely unregulated auctions (i.e. the incentive for bidders to gamble on extremely low-priced bids, and auction outcomes to select those most optimistic bids). With no significant penalties for withdrawal, a substantial proportion of awarded NFFO projects never went ahead (Newbery, 2012).

Two major changes occurred from 2000. In the original privatisation process, competition was conducted through a central pool. A national spot price emerged based on generation bids (to sell at a specific price), and offers to buy, with a top-up charge added to the spot price to fund recovery of investment costs. Due to concentrated market power, however, by the late 1990s, costs and prices increasingly diverged. In 2000, the government moved to bilateral contracts, using competition to reduce the cost–price gap. This change also inevitably removed the capacity top-up.

Second, from 2000, the government replaced the NFFO supports with Renewable Obligation Certificates (ROCs), alongside feed-in tariffs for smaller renewables installations (mainly PV). The generators received ROC certificates, which they could sell to suppliers who were, again, required to meet a mandated percentage of renewables generation (a form of portfolio standard similar to the Chinese GEC system). In practice, the value of ROCs hovered around £50/MWh, which for most of the period was more than the wholesale electricity price, thus more than doubling the revenues to renewable investors (Newbery, 2012).

From about 2005, the VRE growth occurred alongside rapid increases in the wholesale electricity price driven by the large price increases in all fossil fuels. In the context of higher overall electricity prices, the cost of renewables thus attracted more political attention. The industry continued to insist that renewables required substantial subsidies, not least because of the large uncertainties around wholesale electricity prices. As summarised by Grubb and Newbery (2018):

"The renewable generators were responsible for selling their output in the market and were responsible for imbalances, so developers needed to predict wholesale prices, imbalance payments, and ROC prices over the future life of their investment. … Also, since all renewables competed equally, most of the support ended up going to the least risky, best-established technologies – mainly onshore wind projects and co-firing biomass in existing power stations. By 2008, UK renewable capacity ranked almost bottom amongst European countries, despite the UK having some of the best resources."

Banding reforms in 2009 established rules for some less mature technologies to get multiple ROCs. Notably, offshore wind was awarded two ROCs for every MWh of output, in effect a subsidy of about £100/MWh over and above the wholesale electricity price.

2.2 UK CfDs from the 2013 UK Electricity Market Reform

At the end of the 2000s, two official assessments argued that the system had to change: The UK's new Climate Change Committee warned in 2008 that the government's climate objectives would be almost impossible given the existing structures, whilst in 2009 the energy regulator concluded that energy security itself was at risk due to low levels of investment in the liberalised market. A new government in 2010 embarked on a major set of reforms which culminated with the 2013 *Electricity Market Reform*.

Alongside a carbon price floor and a capacity market, this introduced (investment-related) Contracts-for-Difference (CfDs) as a wholly new instrument to support renewables investment through private finance. Such CfDs are 15-year contracts which in effect offer a fixed price for electricity generated, but are implemented through a contract which pays generators the difference between the wholesale market spot price, and a fixed strike price (see Box 1-1).

Technically, the payment settlement formula for the 15-year CfD is:

$$R_{CfD} = \sum Q \times (p_{strike} - p_{ref})$$

R_{CfD} represents the revenues received by a generator with a CfD, p_{strike} represents the generator's strike price, p_{ref} represents the reference price (the day-ahead price), and Q represents the quantity of electricity generated and sold.

Note that CfDs are not technically a subsidy: they are a mechanism to stabilise revenues, underwritten by government. The specific aim is to reduce investor risk, and thereby to reduce the financing costs of private investment capital (i.e. interest rates and cost of equity investments). Whether or not CfDs are a subsidy, or a net saving, depends on how the CfD strike price compares to the long-run wholesale price of electricity.

BOX 1-1:

The UK Contracts for Difference: principles and technicalities

HOW DO CONTRACTS FOR DIFFERENCE (CfDs) WORK?

Figure 1-6: Diagram of CfD operation: the mechanism for delivering a fixed price in variable wholesale market. Source: House of Commons Library.

- A fixed strike price which (after the first administrative round in 2014) is established through a process of competitive bidding of volumes offered for a given price; the constraint at each auction is a pre-stated government constraint on overall contract value (legally, an underwriting guarantee rather than actual government payment).

- In operation, companies are then paid by the Low Carbon Contracts Company (LCCC) the difference between the strike price and a reference market price. This 'top-up' from the LCCC is funded through levies on electricity consumers (who conversely are repaid if and when the wholesale price rises above the strike price). The LCCC is underwritten by government but the contracts are private law contracts, a system designed to minimise the possibility of future government interference undermining investor confidence.

- Given the complex nature of the UK wholesale market with many different bilateral contracts, the reference price is a legal definition, which for renewables is the price in the day-ahead market, often termed the "spot price".

- Modifications to the system in 2021 included that new generators will not receive their top-up payments when the reference (day-ahead) price is negative (see Section 5.1).

- To encourage technology diversity and innovation in less advanced technologies, there are separate auctions for three pots: established onshore renewables, offshore wind energy, and less established technologies.

- There are also price caps in each auction, which may also vary according to the different technologies involved.

2.3 Outcomes of UK CfDs

The CfD system and its institutional architecture took several years to design and legislate. To minimise further delays, the government promptly issued a first round of administered contracts based on negotiations (including for a nuclear power plant, as well as wind and other renewable energy projects).

After that, CfDs were priced and allocated through pay-as-clear, reverse-price auctions. Companies bid project-specific capacities for specified strike prices, and the government selects projects from the cheapest bid up (within a given category), until a predefined overall budget is exhausted. Along with this and rigorous pre-qualification criteria, additional mechanisms ensure commitments to projects and minimise the risk of 'winners curse' outcomes of unviable projects.[22]

This system of CfDs achieved remarkable results. Given the security and predictability of the price received for output, private capital poured into renewable energy. With the introduction of the first Auction Round (AR1) in 2014 for these 15-year contracts, costs fell sharply across all the major renewable technologies.

In 2015, following a new government effectively banning onshore wind energy (largely due to internal party politics), attention turned to offshore wind. The subsequent progress of offshore wind in CfD auctions is summarised in Figure 1-7.

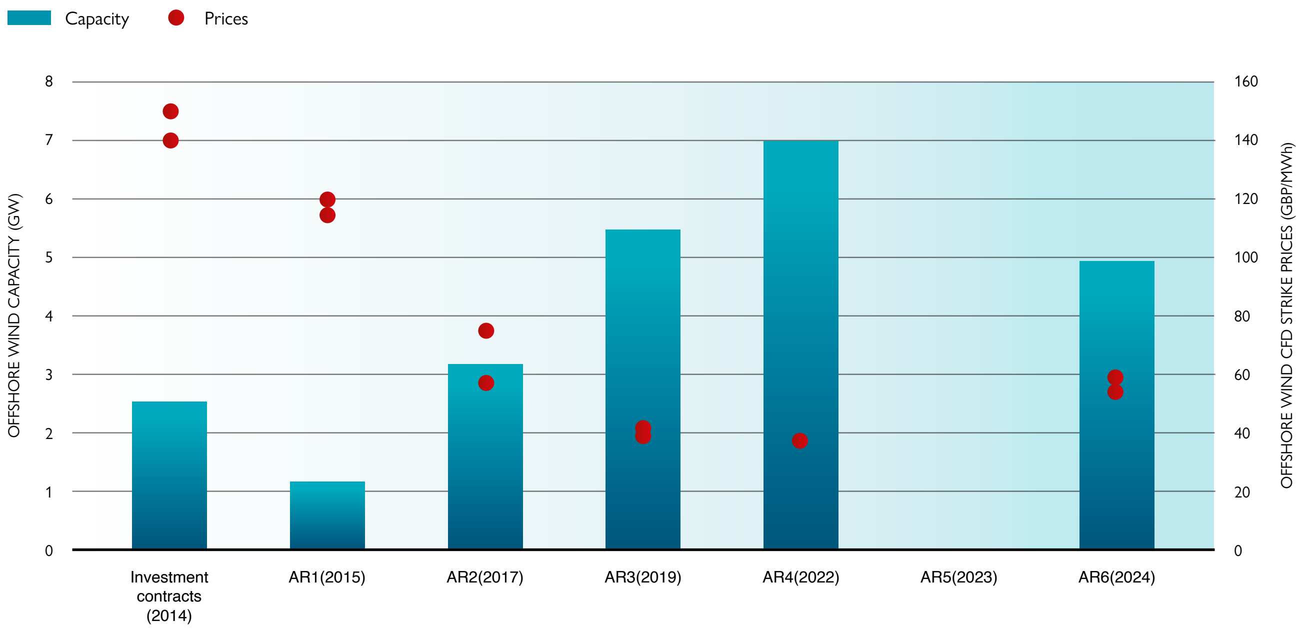

Figure 1-7: UK offshore wind CfD auction outcomes (2014-2024).
Note: The blue bars show the capacity of awarded CfDs, at prices shown by the red dots (in 2012 GBP), in each of six auction rounds (AR1 – AR6). These followed initial government contracts arising from direct negotiations (2014). Some years have multiple prices due to varying start dates. Source: Grant Thornton and Poyry (2015) and Low Carbon Contracts Company (2024).[23]

[22] More detailed explanations of the UK CfD system are given in websites from the UK government (Contracts for Difference - GOV.UK) and the Low Carbon Contracts Company (About - Low Carbon Contracts). Note also that the UK approach to CfDs is not the only approach. For many years, some continental European countries operated one-sided CfDs, in which there was a guaranteed minimum price, but companies did not have to pay back if the wholesale price rose above the strike price – a system which caused major controversies when the 2022 energy crisis hit. For a brief European overview see EUI Contracts-for-Difference (CfDs).

[23] CfD cost data are in constant 2012 GBP. Using a multiplier of 1.59 from the UK Office of National Statistics' Retail Prices Index, this sees the prices in the latest auction rise from £58.87/MWh for new offshore wind contracts and £54.23/MWh for resubmitted capacity in 2012 prices to £81.95/MWh for new offshore wind projects and £75.38 for resubmitted capacity in 2024 prices.

Overall, the results were dramatic:

- In 2013, after a decade of support from the ROCs, the UK had less than 4 GW of offshore wind capacity. By 2024 this had grown to almost 15 GW installed, with more than an additional 12GW already in progress through the contracts awarded in the 2022 and 2024 auctions.
- Within a decade, the cost of offshore wind fell by more than a factor of three, from over £150/MWh in 2013 to around £40/MWh in 2022 (measured in 2012 GBP). Auction prices did, however, climb again in the 2024 auction for reasons described below.

Analysis of the causes of this dramatic cost decline points to four contributing factors (Jennings *et al.*, 2020):

- Innovation through research and development, both public and private, being stimulated by industrial collaboration convened through a government-backed Offshore Wind Accelerator, combined with the scale of the growing market;
- Learning-by-doing, as experience revealed lessons and areas of improvement;
- Scale economies, for example in turbine size and supply chains; and
- Financing costs: the interest rate charged for private finance of renewables fell substantially as the perceived risks reduced, and as the CfDs provided stable and more predictable revenues. This also facilitated a move from reliance mainly on equity funding to a far greater role for cheaper bank finance (Maximov *et al.*, 2024).

These factors can each be understood as contributing to the reinforcing feedback of renewable deployment and cost reduction, shown above in Figure 1-2.

Concerning the financing costs, Newbery (2016) estimated that the move from ROCs (a subsidy on top of variable wholesale prices), to fixed price contracts, reduced the cost of financing by over 3 percentage points—representing a saving of over £2 bn/year on the overall cost of financing the scale of investment required for the UK's offshore wind plans.

However, the fifth UK auction (AR5, held in 2023) did not result in any successful offshore wind bids. This was mainly because the aftermath of the 2022 energy crisis had resulted in inflation, a rapid increase in interest rates, and a rush of offshore wind investments globally increasing pressure on supply chains. None of these factors had been considered by the government when setting the auction price ceiling. The most recent CfD auction (AR6, Autumn 2024) did procure about 5GW of new offshore wind, but at a significantly higher price than in 2022. This was due to these same pressures, combined with a growing concern about the possible impact of VRE surplus events.

Despite the success achieved by the traditional UK CfD mechanism, changing conditions have revealed new challenges with the policy's design. Firstly, it may distort VRE investment signals. Continuing to incentivise VRE investment will increase the frequency of VRE exceeding demand, reduce the profitability of VRE, and affect investment in VRE unless there is a suitable capacity of energy storage.

This dynamic will be exacerbated by the clustering of offshore wind in Scotland and transmission constraints impeding the flow of power from these generators to the UK's demand centres in England. When the transmission system becomes overburdened, generators located behind these constraints are paid to turn down, while those on the other side are paid to ramp up. These transmission constraints have already become a significant problem, with 10% of wind power curtailed in 2024 (Millard, 2025).

The CfD also provides no locational signals; generators receive their strike price regardless of whether their power can reach consumers. In 2024, Scottish wind farms received £390 million in constraint payments (Perry, 2025); constraint payments have rapidly increased in recent years. For this reason, the UK government is currently considering de-coupling CfD payments from output, providing top-ups instead based on hypothetical maximum output, regardless of the proportion of electricity ultimately curtailed due to transmission constraints (to be explored in greater detail in Section 6.2).

Curtailment due to transmission constraints is not the only problem facing CfDs, however. For the UK, it is expected that VRE output will exceed electricity demand nearly 50% of the time by 2030 in the absence of any system flexibility, up from only 2.4% in 2023 (Brown *et al.*, 2024) (see Figure 1-8 for a comparison between VRE capacity projections and electricity demand in 2023). This means that in a conservative deployment scenario, 27% of wind power generated in 2030 would be wasted as surplus, rising to 37% in a scenario assuming more ambitious deployment.

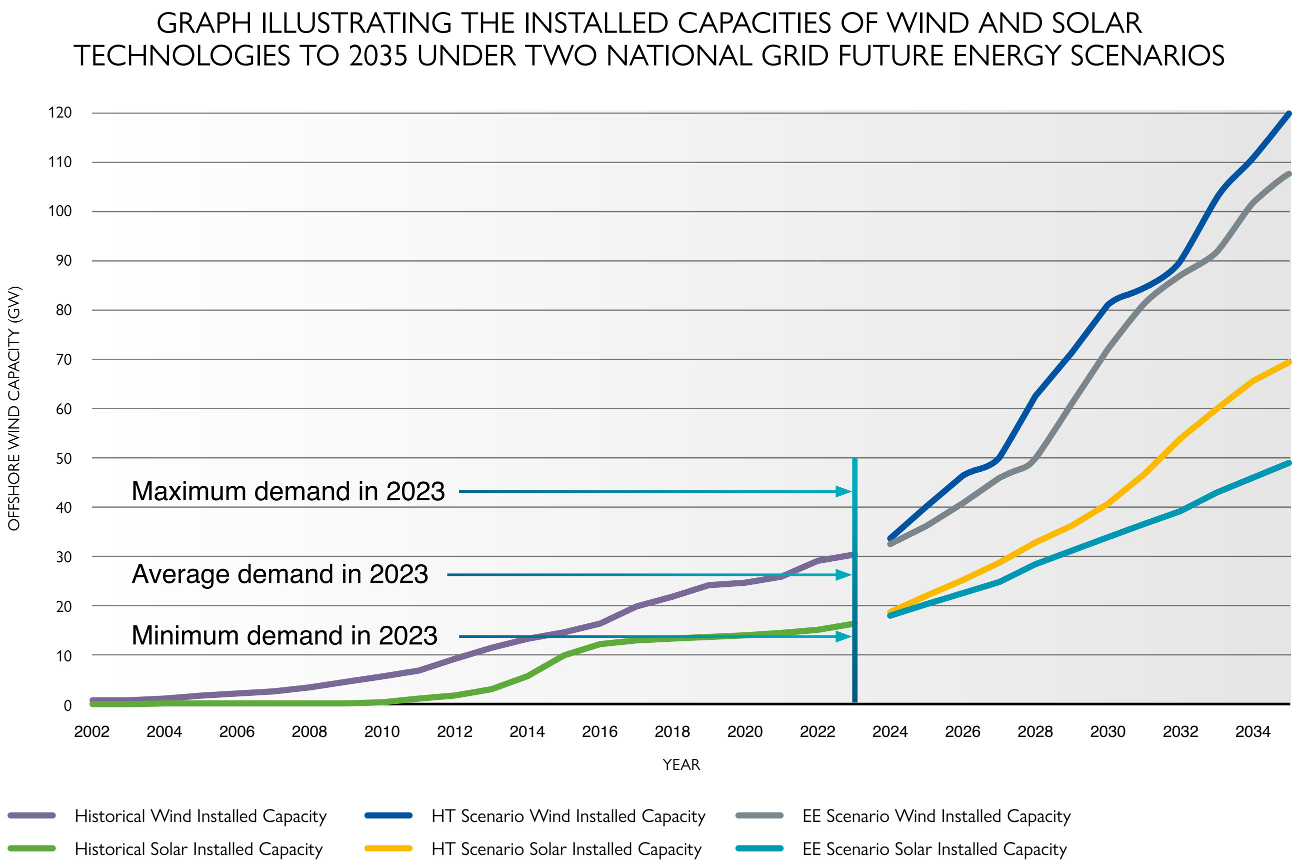

Figure 1-8: Evolution of VRE installed capacity in the UK.
Note: Historical installed capacities of wind and solar shown to 2023, followed by the projected installed capacities under National Grid Future Energy Scenarios over 2024-35.[24]

Under the current CfD design, generators do not receive payment when electricity prices are negative, meaning renewable generators could face considerable profit risk. This risk could disincentivise further investment in renewables, limiting the UK's ability to meet its clean power targets.

Secondly, it may distort the operational signals of VRE. Using CfDs to guarantee electricity prices incentivises VRE to generate as much as possible whenever the day-ahead price is non-negative, regardless of actual power output needed, driving up constraint costs for the system operator. The implications of this will be discussed further in Section 6. Furthermore, CfD-backed assets can distort the merit order in the balancing mechanism during turn down actions by requiring payments equal to their foregone difference payment. They can also distort ancillary service markets—when day-ahead prices are non-negative, VRE generators will only provide turn-down ancillary services when their potential payment exceeds their foregone CfD top-up payment. The UK CfD therefore creates misalignment between project-level and system-level efficiency by distorting operational incentives. This drives up overall system costs, and if policy is not responsive to correct these inefficiencies, the issue will only become more pronounced as VRE capacity grows.

[24] These capacity projections are based on the Energy System Operator's (2024) Future Energy Scenarios. The two scenarios used (Electric Engagement (EE) and Holistic Transition (HT)) represent different trajectories for meeting net zero by 2050 in the UK. EE assumes most demand is met via electrification, while HT uses a mix of hydrogen and electrification.

3. Challenges for sustaining VRE investment in China

3.1 Dampening feedbacks with GECs and Portfolio Standards

As noted in Section 1, China's GEC scheme[25] has to date had very low prices, far too low to meaningfully support investment in renewables. To buttress the system in the post-subsidy era, China launched the Renewable Energy Portfolio Standard (RPS) system in 2020.[26]

The RPS sets targets for renewable energy as a share of power sold (for state-owned electricity distribution companies, retail electricity companies and independent retail electricity companies), and as a share of power consumed (for electricity users who purchase electricity through the electricity wholesale/merchant market and companies that operate their own power plants). These targets are updated annually by the National Development and Reform Commission (NDRC) for the coming year for each province. Companies buy GECs to demonstrate their compliance with the RPS targets.

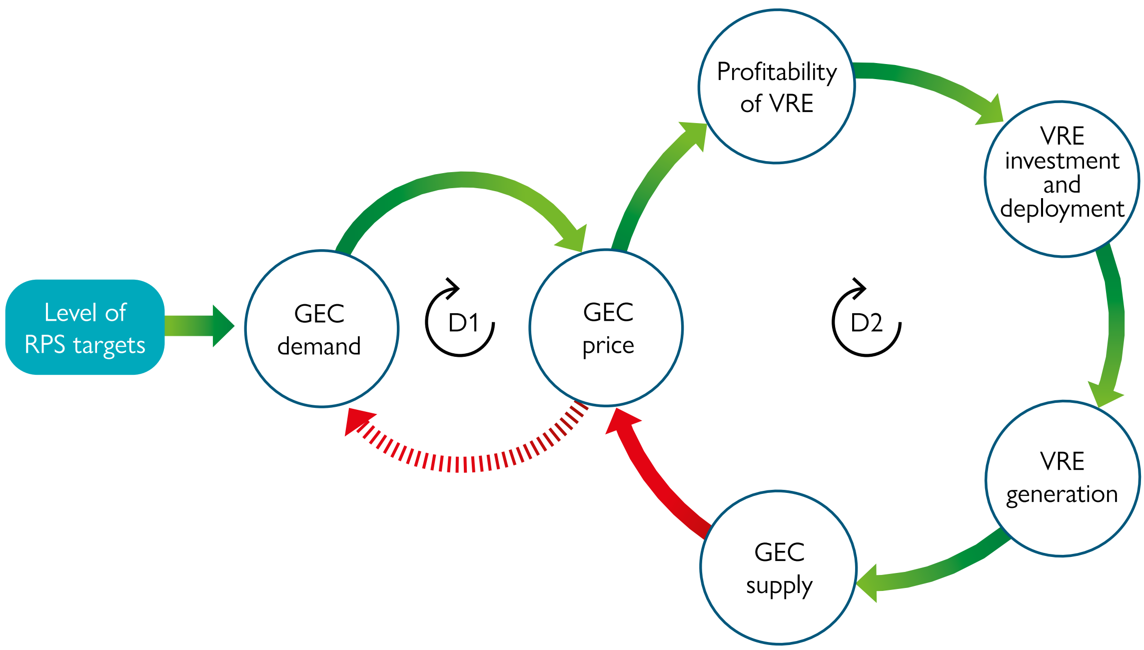

Figure 1-9: CLD showing dampening feedbacks of GEC market.
Note: Green arrows indicate a positive relationship (i.e. factors move in the same direction) and red arrows indicate a negative relationship (i.e. factors move in opposite directions). A dotted arrow indicates a weak or conditional relationship. White nodes represent variables in the system. Blue rectangular nodes represent policy factors. The letter "D" denotes dampening feedback loops.

[25] We acknowledge that the Chinese government published several updates to the GEC system in the middle of March 2025, however there has not been sufficient time to process and adjust this report based on these modifications.
More information on these changes can be found at: https://www.ndrc.gov.cn/xxgk/zcfb/tz/202503/t20250318_1396627.html and https://www.nea.gov.cn/20250318/78dbc76b24434bd9ae9db87c3e1f18eb/c.html

[26] See NDRC and NEA (2019). Notice on establishing a robust renewable energy consumption guarantee mechanism. 发改能源[2019]807号

Maintaining a GEC price high enough to support investment is difficult because the policy has a built-in dampening feedback: if it succeeds in causing more renewables to be deployed, this will increase the supply of GECs, and that will tend to decrease the GEC price (Figure 1-9). High GEC prices can, however, be supported by strong RPS targets, as the extra demand created through higher targets acts to inflate GEC prices, potentially forming a kind of price floor mechanism.

The GEC system bears some similarities to the UK's ROCs. The UK attempted to tackle the problem of price cannibalisation by implementing a 'buy-out' price cap. If suppliers do not purchase sufficient ROCs to meet their obligations, they are required to pay this buy-out price per unit of their ROC shortfall. The regulator set the target volume for ROCs deliberately in excess of feasible deployment, in effect, ensuring that the price of all ROCs stayed at the buy-out price. However, this system worked only to a limited extent, partly because the funds suppliers paid to meet their ROC shortfall were distributed back to all suppliers, dampening incentives to deploy enough renewables to meet their obligations.

3.2 Dampening feedbacks of cannibalisation

It is far from clear that strengthening the RPS targets in China to bring the GEC price up—even if the extreme UK solution were adopted —would overcome the challenges facing VRE investment.

This is because it would only partially offset one of several more fundamental dampening feedbacks in the wholesale market that risk undermining VRE investment as capacity grows and markets liberalise (Figure 1-10):

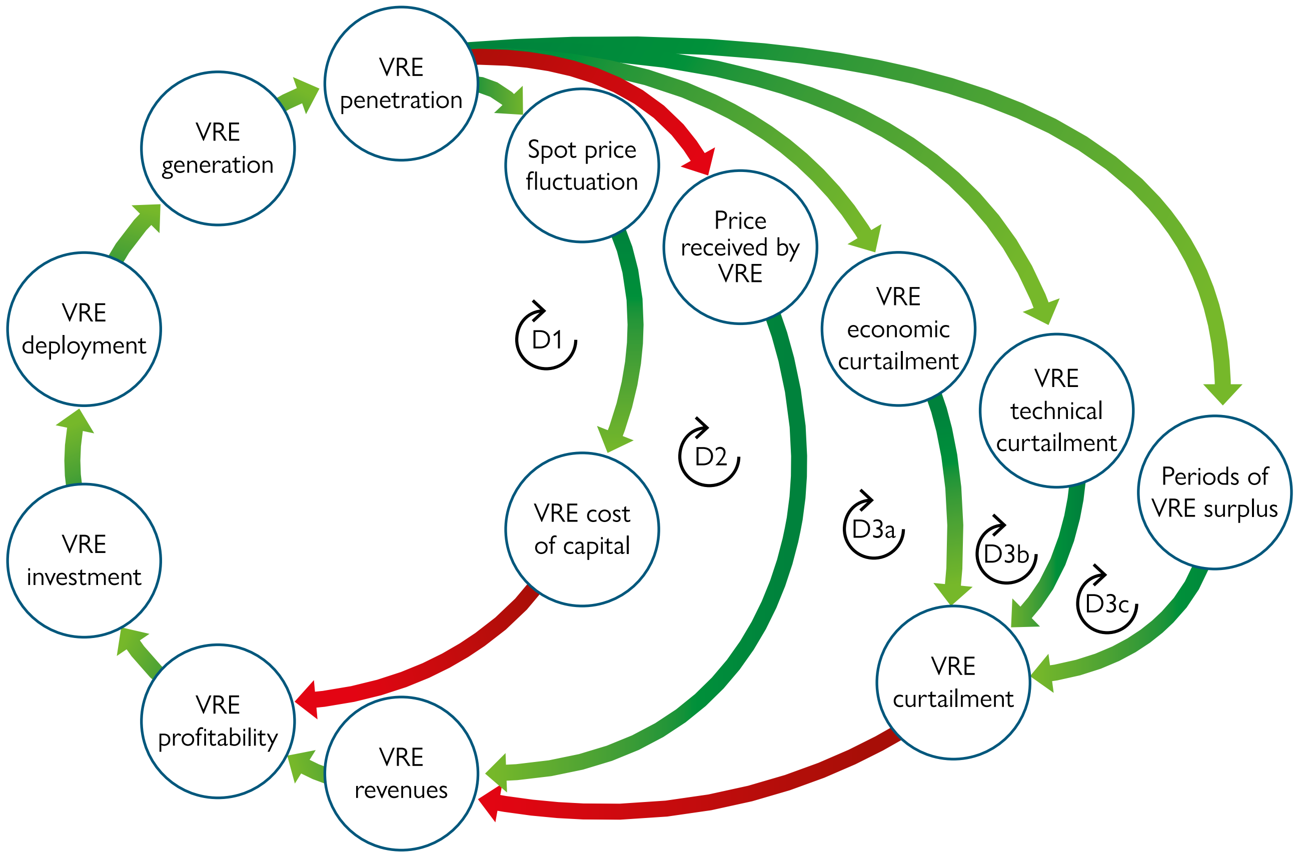

Figure 1-10: CLD showing multiple channels of VRE revenue cannibalisation.
Note: Green arrows indicate a positive relationship (i.e. factors move in the same direction) and red arrows indicate a negative relationship (i.e. factors move in opposite directions). The letter "D" denotes dampening feedback loops.

Specifically, three dampening feedbacks act through the following channels:

1. **Merit order price reduction (loop D2 in Figure 1-10).** As VRE penetration rises, grids will experience periods of high supply during times of VRE generation (e.g. midday peak). Higher-cost generation sources may be pushed out of the merit order, and will be needed less often. This will reduce the market clearing price during periods of high VRE generation, reducing VRE profitability. Halttunen et al. (2020) detailed these merit order effects, with initial estimates of how much rising renewable capacities may reduce the prices secured.

2. **Volatility (loop D1 in Figure 1-10).** High levels of VRE penetration increase volatility of spot market prices, reduce the predictability of market returns, and increase the investment risks of renewable energy while the system is transitioning. This is particularly true insofar as uncertainty over future trends in supply, demand, and the generation mix create uncertainties regarding potential revenue capture opportunities. As liberalisation increasingly exposes VRE projects to price signals, these uncertainties may cause financiers to reassess risk premiums and interest rates, leading to an increase in project financing costs.

3. **Volume risk (loops D3a, D3b, D3c in Figure 1-10).** Besides price risks, the expansion of VRE supply also increases volume risk, which refers to uncertainties regarding the ability of VRE projects to sell the power they generate. Inability to sell power generated can arise from technical curtailment (when grids are unable to absorb VRE due to network or system constraints), economic curtailment (when VRE is bid out of dispatch), or VRE surplus events (when instantaneous VRE generation surpasses total demand). This volume risk creates additional revenue uncertainty, weakening incentives for further investment.

In Chinese provinces where the renewable share of generation is highest, there are already signs that increasing VRE penetration is beginning to lower electricity prices. For example, spot prices in Shanxi and Shandong increasingly exhibit patterns characteristic of systems with growing VRE (especially solar) penetration—such as very low prices during daylight hours (see Figure 1-11).

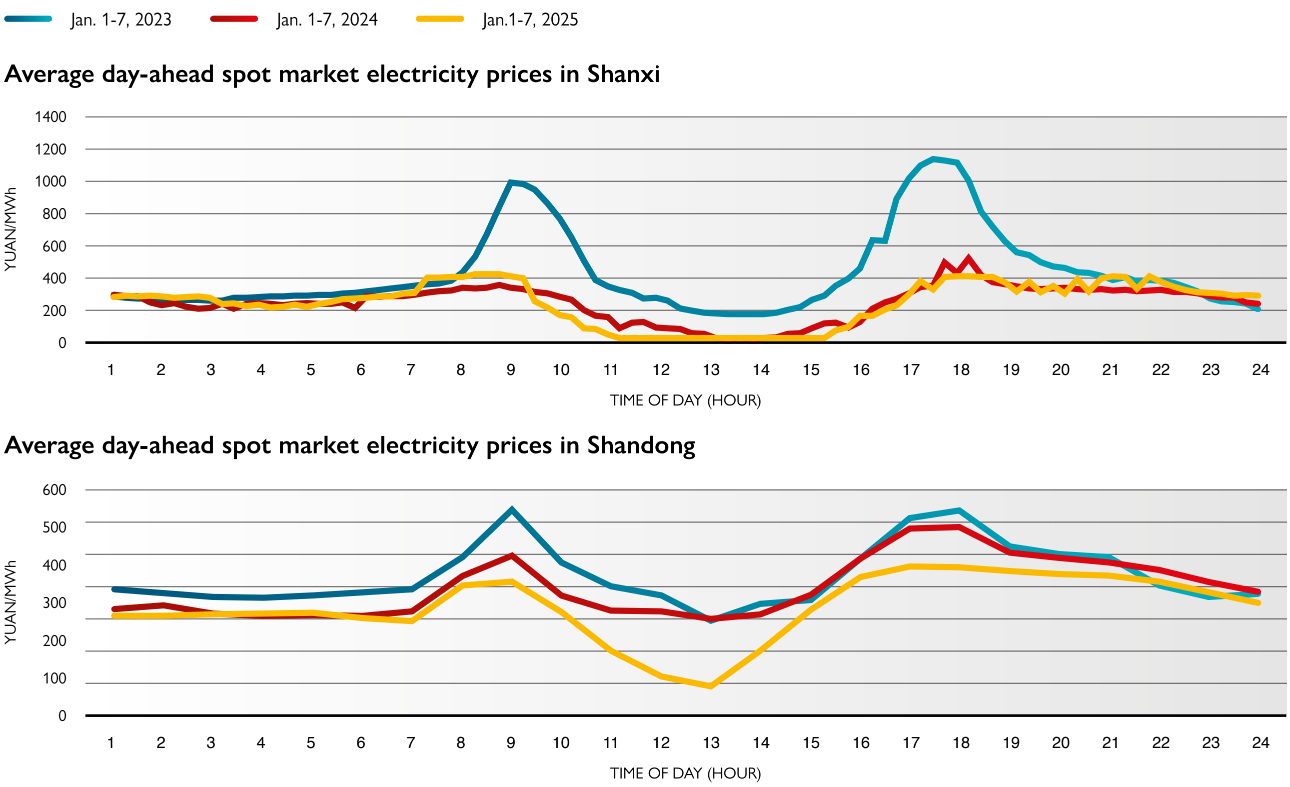

Figure 1-11: Average day-ahead spot market electricity prices in Shanxi and Shandong from 1-7 Jan 2023, 1-7 Jan 2024, 1-7 Jan 2025.
Data source: Shanxi and Shandong electricity trading centres.[27]

[27] Data from Shandong Power Exchange Centre website and the Beijing Power Exchange Centre mobile app.

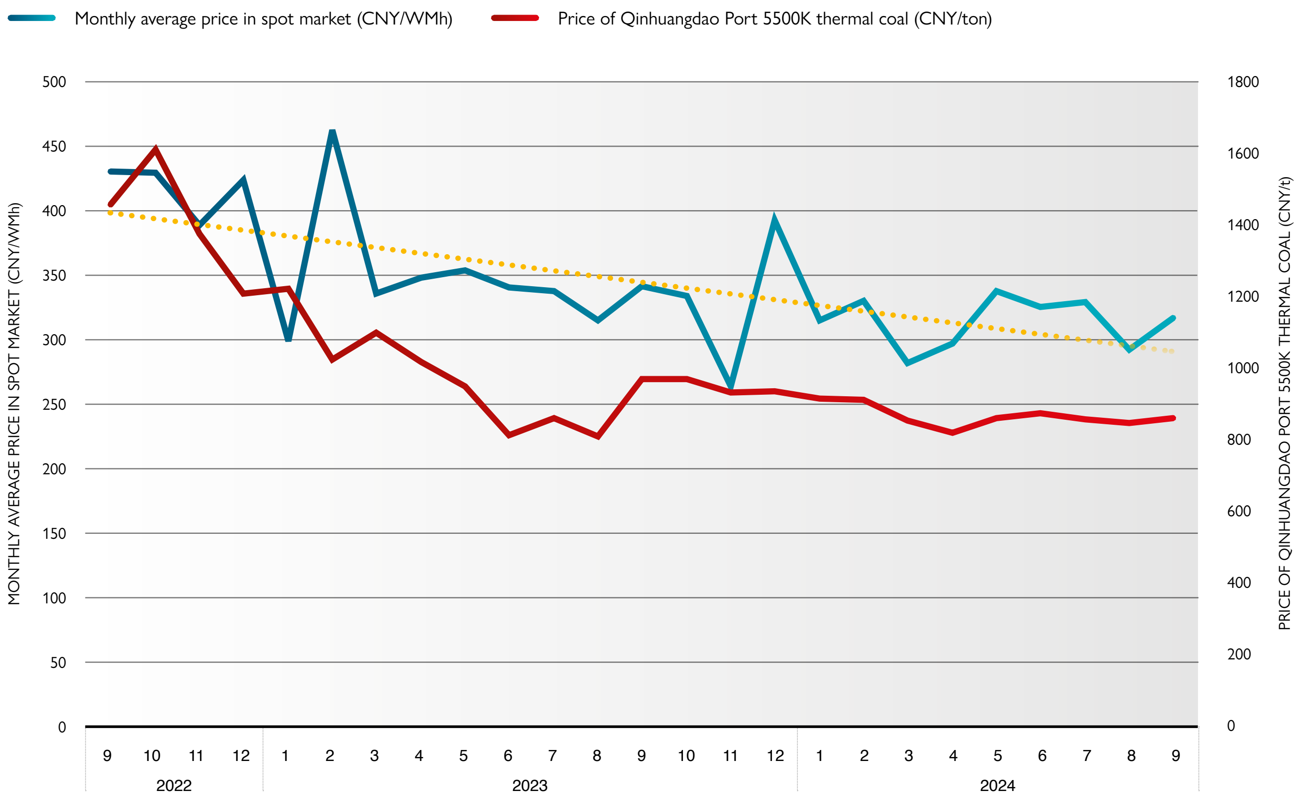

Figure 1-12: Comparison between Shanxi electricity spot prices and coal price.
Note: The blue line shows the monthly average spot market price in Shanxi, and the yellow dotted line is a trendline for this data. The red line shows the price of Qinhuangdao port 5500K thermal coal. Data from Shanxi Electricity Trading Centre[28] and Wind database.

Over the mid- to long-term timescales, however, decreases in average spot prices to date are probably more likely to have been driven by falling coal prices (see Figure 1-12).

To address the cannibalisation issue, policy must break the dampening feedbacks present in Figure 1-10. The sale of GECs (with tightening RPS targets) could increase the profitability of renewables sold in the spot market, weakening dampening feedback D2, but it would not reduce either the price or revenue volatility in a system with growing VRE penetration (feedback loop D1), or volume risks associated with curtailment (loops D3a, D3b, D3c). CfDs, on the other hand, can potentially break all three feedback loops, subject to various policy design choices (see Section 6 below).

The volatility of revenues, and the way this deterred (and raised the cost of) private investment, was the principal reason for the UK abandoning its ROC system.

However, there was also an increasing recognition that ROCs would not provide any protection against volume risks associated with periods of surplus generation. Furthermore, ROCs create spot market distortions by incentivising generators to submit negative bids in the wholesale market—to pay £30/MWh, for example, if it enables them to find a buyer for their power, and thereby get a ROC credit worth £50/MWh.[29]

In 2023, Great Britain had 214 hours of negative prices in the day-ahead electricity market—a tripling from the previous year—and the frequency is rising rapidly (Drax Electricity Insights, 2023). Negative wholesale price events are becoming increasingly frequent across Europe, and are already starting to deter renewables investment (Tani and Millard, 2024).

[28] See Shanxi Electricity Trading Centre WeChat account.
[29] Generators on the early rounds of CfDs are paid their strike price however deeply negative the wholesale price dives, so could drive the price even lower—a problem fixed with negative pricing reforms in 2022 (see Section 6).

3.3 Direct consumer engagement with renewables: a way to circumvent the wholesale market?

Given the multiple investment risks for merchant investment in the wholesale market—represented by the feedbacks indicated in Figure 1-10—the move to government-backed CfDs involves taking renewables investment decisions out of the market (same for feed-in-tariff prices mandated by government).

Some renewables investment in the UK has occurred through other channels. Notably, power purchase agreements (PPAs) based on VRE generation have become popular for two main types of consumer groups seeking to contract directly with renewables (beyond direct wire connections which do not physically connect with the main grid).

First, for large industrial consumers, the motivation has included both the desire to meet environmental commitments to use green power (e.g. RE100 commitments), and to avoid the volatility and uncertainties of the wholesale market. Sometimes these arrangements involve direct investment by industry users in renewables. Second, some supply (retail) companies have entered into PPAs, especially if they are looking to market their electricity as genuinely sustainable whilst avoiding the controversy risks around tradeable green certificates. VRE PPA contracts vary considerably in their terms and motivations. Some have long-term fixed price elements, others are partially or wholly linked to the wholesale price, serving simply to guarantee VRE offtake.

Regardless of form, however, the UK's PPA contracts have experienced three main limitations:

1. Because they typically involve bilateral agreements between generators and a single purchasing entity, they lose the efficiency benefits of aggregating supply and demand sources.

2. They create some counterparty risk—the risk of the generator failing, or the buying company going bankrupt. The latter was a particular problem in the energy crisis of 2022, when many supply companies in the UK collapsed.

3. Their complexity makes administrative costs often quite high.

One option considered initially in the UK REMA process was to place renewable obligations on supply companies (as with the former ROCs system), but generators were similarly worried about complexity and the creditworthiness of some supply companies compared to government-backed contracts, and the idea was thus dropped.

Another option proposed by researchers was to aggregate renewables through an electricity pool potentially operating similarly to the UK pool in the 1990s, and the Nordic electricity pool, but restricted to renewables (Grubb, Drummond and Maximov, 2022). In effect this would create a dual market structure, in which some or all VRE output would be aggregated through the green power pool directly, selling on to customers through long term contracts which reflected the investment costs, rather than the wholesale price. This power could be directed at specific groups, like low-income households or energy-intensive industry, lowering the prices they face, which is a government priority.

A principal potential benefit would be providing consumers with relative price stability without sacrificing incentives for operational efficiency. The original proposal illustrated application to a pool of CfD-backed generators. UK researchers are currently exploring the potential value of a green power pool approach for stabilising prices for VRE generators after any support contract expires, aiming to mitigate potential cannibalisation risks posed to these generators if fully exposed to the future wholesale market. Potentially, depending on the exact design, a green power pool could weaken, if not eliminate, all three of the dampening feedbacks illustrated in Figure 1-10. While the concept was explored during the government's REMA reform process, there were concerns about how the pool would affect prices in the wholesale market. The design was ultimately rejected due to a considerable number of uncertainties and concerns from the government that such a major change would endanger the electricity system's decarbonisation timeline (DESNZ, 2024).

4. Existing arrangements for power contracts and CfDs in China

4.1 MLT market contracts

Most electricity trading in China occurs through medium- and long-term contracts (MLTs).

These are the backbone of power "markets" in China and the vast majority are one-year contracts, supplemented by monthly or other intra-year contracts. Their aim is to reduce contracting and related budgetary risk for parties, especially thermal plants, which need to sign contracts with coal suppliers. For VRE generators, there are two main options for trading: conventional MLT transactions (which only trade electrical energy) and green power trading (which involves trading both energy and GECs).

VRE generators typically sign MLT contracts at least a month in advance and must deliver power according to the contract's predefined power curve. In provinces where spot markets have been operating, the deviation between the actual power generation and the contracted power quantity can be covered through spot trading. In provinces without spot markets, the rolling MLT markets can mitigate deviations. However, significant deviations may still incur penalties under some occasions.

Now, in certain provinces where spot markets are established and operational, MLT contracts can be settled financially via a CfD-like mechanism. In economic language, these are fixed-for-floating swaps, relevant when one contract party is exposed to variable prices and wishes to stabilise them. The MLT contract locks in a strike price, with the spot market providing a reference price to calculate the CfD payments to the MLT counterparty (either the grid or industrial users). Surplus or deficit generation is then traded on the spot market. Compared with the clearing of all electricity volume in the spot market, the MLT market contracts lock in part of the revenue in advance, and to a certain extent, hedge against the risks of electricity volume and price.

This MLT-CfD arrangement is clarified by the Basic rules for electricity spot markets (trial), issued by NDRC and NEA in 2023[30]:

$$R_{total} = R_{spot} + R_{MLT}$$

$$R_{spot} = \sum(Q_{total} \times p_{spot})$$

$$R_{MLT} = \sum(Q_{MLT} \times (p_{MLT} - p_{ref}))$$

R_{total} represents total revenues, R_{spot} represents revenues from spot market transactions, and R_{MLT} represents revenues from MLT contracts. Q_{spot} represents the quantity of electricity sold on the spot market in any settlement period and p_{spot} represents the spot price during that period. Q_{MLT} represents the quantity of output covered by MLT contract in any settlement period, p_{MLT} is the price set in the MLT contract, and p_{ref} is the reference price, which is equivalent to the spot price in provinces where spot markets are set up.

If we thus assume $p_{ref} = p_{spot}$, then rearranging terms then gives:

$$R_{total} = \sum((Q_{total} - Q_{MLT}) \times p_s + Q_{MLT} \times p_{MLT})$$

This arrangement shows that the portion of revenue represented by $Q_{MLT} \times p_{MLT}$ is locked in by the MLT contract, with the remainder dependent on spot trading. Note that, according to this formula, if generators deliver less than their contracted output, they still need to pay the difference between the contracted electricity and their actual generated electricity based on the spot market price, thus maintaining revenue uncertainty.

To emphasise however, whilst the mechanism is similar, the MLT-CfDs are totally different in purpose from UK CfDs, in that they protect, annually, year-ahead revenue. Unlike the 15-year CfDs of the UK they are not, in their current form, so relevant to renewables *investment*. Generally, multi-year CfDs are more conducive to enhancing investor confidence and promoting the development of renewable energy.

[30] NDRC and NEA (2023). Basic rules for electricity spot markets (trial). 发改能源规[2023]1217号

4.2 Government-authorised contracts for renewables

Recognising the risks faced by renewables, some provinces had taken steps to stabilise revenues using a price difference settlement mechanism, which functions similarly to CfDs. Termed "government-authorised contracts" (GACs), specific implementation details have varied between provinces (see Table 1-3). The strike prices for different settlement mechanisms are set by provincial governments, not via competitive processes, and are based on the local coal-fired benchmark price. In addition, unlike the 15-year CfDs in the UK, there is no official guarantee period for this mechanism, which can vary depending on the type of project and local policies.

Mooted in 2022 in *Document 118*,[31] GACs represent a progression from the guaranteed purchase regime. Unlike the MLTs signed between electricity generators and consumers, the government acts as the counterparty for these contracts. The electricity volume covered by the GACs is settled based on the price difference between the strike price and the market reference price, with any costs allocated to industrial and commercial users.

The extent to which these current arrangements limit price and quantity risks for investors in renewable power is summarised in Table 1-4.

The shift to market-oriented trading of renewable power introduces both price and volume risk to developers' revenues, as shown in Table 1-4. The GAC arrangements in the MLT market limit these risks, but only up to one-year in advance. Coupled with the fact that strike prices may be adjusted on a year-to-year basis by governments via non-competitive means, this arrangement may not engender sufficient investor confidence to sustain high levels of deployment, as investment decisions are made according to revenue projections with 20-year time horizons. In addition, the strike price of GACs obtained through non-competitive means is decoupled from the actual costs associated with producing VRE. These shortcomings were, however, addressed in the newly-released *Document 136*,[32] issued in February 2025.

Table 1-3: Comparison of VRE revenue support mechanisms in Xinjiang and Guangxi.

Province	Subsidy recipients of CfDs	Strike price	Local coal-fired benchmark price
Xinjiang	Covers generation from all VRE projects built after 2021	0.262 CNY/kWh	0.25 CNY/kWh
Guangxi	Covers all VRE generation that is not subject to guaranteed purchase	0.38 CNY/kWh	0.42 CNY/kWh

Table 1-4: Comparison of effects on price and volume risk of different electricity trading mechanisms in China.

	Guaranteed purchase quantity	Quantity covered by MLT contracts	Quantity in excess of that covered by MLT contract
Price risk	None – price is fixed	None for the duration of the contract (typically 1 year) because difference contracts (not an investment-supportive CfD) top up the price of any electricity sold in the spot market to the MLT contract price, within this quantity. Increasing price risk in future years, if MLT prices are influenced by the spot market price.	High – price (for this quantity) is entirely set by spot market.
Volume risk	None – quantity is fixed	None in the short-term, if MLT contracts are fully-executed. Increasing volume risk in future years, if VRE supply (and must-run thermal) more frequently exceeds total market demand.	High – this volume is entirely dependent on spot market.

[31] NDRC and NEA (2022). Guiding opinions on accelerating construction of a unified national power market system. 发改体改[2022]118号
[32] NDRC and NEA (2025). Notice on deepening market-oriented reform of new energy on-grid prices and promoting the high-quality development of new energy. 发改价格[2025]136号

4.3 *Document 136* mechanism and comparison to UK CfD

Document 136—or *Notice on deepening market-oriented reform of new energy on-grid prices and promoting the high-quality development of new energy*—contains several major policy changes that usher in a new chapter of power market reform and VRE development in China.

Most notably, the document establishes a *price settlement mechanism for the sustainable development of new energy*, which functions similarly to an investment-supportive CfD, building on the GAC concept by introducing competitive reverse auctions and ensuring that power generators can secure stable returns over a multi-year period.

Certain details regarding implementation remain undecided, as these will be specified in province-level policy later in 2025, but some general comments can be made based on the NDRC and NEA's directives contained in the document.

Document 136 outlines new pricing mechanisms for VRE projects, with separate provisions for existing projects and new ones that connect to the grid after 1 June 2025. Here, we focus our analysis on the latter mechanism, as it is most relevant for future investment decisions. This mechanism bears some resemblance to the UK CfD, with notable similarities including:

1. **Strike price auction mechanism**—in both the UK and Chinese-style CfDs, strike prices are set by the highest winning bid in a reverse auction process, with predefined price ceilings set by government.
2. **Two-sided settlement**—in both settings, if the reference price is below the strike price, generators receive the difference; if the reference price is above the strike price, generators pay back the difference.
3. **Mid- to long-term revenue certainty**—both instruments are designed to stabilise revenues over the mid- to long-term to de-risk investment. However, the exact time scales differ: UK CfDs are valid for 15 years, whereas the validity of the Chinese versions will align with the necessary duration to facilitate investment cost recovery—likely 8-10 years according to industry experts.
4. **Technology competition**—UK CfD auctions are separated by pots; different pots correspond to different levels of technological maturity to ensure that nascent generation technologies do not compete with established ones. In auction round 6 (2024), solar PV, onshore wind, and hydro all competed against each other as established technologies. In China, detailed guidance on this point has not yet been released, but *Document 136* encourages using separate auction pots when there are significant differences in technology costs.

However, despite their similarities, the two countries' CfD policies contain major differences. This is not surprising given the vast differences between the two in their governance and policy environments, historical contexts, and progress on the transition. Key differences include:

1. **Project-level coverage**—the UK CfD covers 100% of a CfD-backed generator's output, whereas the Chinese version provides only partial coverage, subject to provincial government decisions. Initially, coverage will match the proportion of output previously covered by guaranteed purchase policies.
2. **Scale of total capacity coverage**—the scale of total UK CfD coverage is set by auction budgets determined by government ahead of each auction round. In China, provincial governments will determine the scale of each round of annual auctions based on progress against renewable energy consumption targets.
3. **Strike price auction floor**—Chinese CfD auctions will likely employ price floors to prevent "unhealthy competition" (projects bidding infeasibly low prices to win market share); the UK scheme does not use price floors.
4. **Reference price market**—the reference price for calculating UK CfD payments is the day-ahead market price. In China, provinces that have set up functional spot markets are directed to use real-time spot prices as the reference price; those that have not are to use prices from MLT markets.
5. **Reference price calculation**—reference prices for CfD-backed assets in the UK are based on the prices received by each individual generator, so each generator receives its strike price for every MWh of power it produces. In the Chinese policy, reference prices are calculated as the average price received by generators of the same technology within a province. This could mean, for example, that the reference price for all onshore wind farms in a province is the same in a given month. Thus, differences in earnings arising from location (e.g. proximity to high-price nodes) or trading

strategies will translate to differences in total revenues. As such, two onshore wind farms awarded CfDs in the same year and province may have the same strike price but end up with different total CfD-associated revenues.

6. **Difference payment funding mechanisms**—the difference payments for the Chinese CfD are to be funded by charging them as system costs (which mostly fall to commercial and industrial users); in the UK, they are passed through to all customers via retailers.

7. **Implementation governance**—UK CfD policy is designed and implemented by the national government. In China, the central government provides guidance and directives (e.g. via *Document 136*), but exact arrangements and prices are determined by provincial governments.

Table 1-5: Comparison of Chinese-style CfD described by *Document 136* and the UK CfD.

	Chinese-style CfD, as applicable to projects connected after 1 June 2025	UK CfD
Scale	■ Does not necessarily cover generators' entire output ■ Covers a proportion of output, which will initially match the proportion previously covered by guaranteed purchase policies ■ Coverage to be decided by provincial authorities	■ Covers generators' entire output ■ Government determines total auction budget ahead of each auction round
Strike price	■ Set by highest winning bid in reverse auction process ■ Government sets predefined auction price ceiling ■ Auction price floor may be set to avoid unsustainable competition	■ Set by highest winning bid in a reverse auction process ■ Government sets predefined auction price ceiling based on estimated construction and operational costs for each technology
Reference price	■ Where spot markets are operating, reference price is calculated as monthly average of real-time prices received by projects of the same type ■ Where there are no spot markets, reference price is the monthly average of MLT contract prices for projects of the same type	■ Day-ahead market price
Duration	Duration is to align with average period of investment cost recovery (estimated to be 8-10 years in most cases)	15 years
Funding mechanism	Costs passed on as system costs	Costs charged to electricity retailers, who pass them on to consumers

4.4 Locational pricing and CfDs

Background on locational pricing

As the transition to clean power progresses, the outcomes for electricity prices and security of supply may depend strongly on how interprovincial market connectivity, transmission infrastructure, and geographical imbalances in the power system are managed.

There are large differences in the net supply of electricity (generation minus consumption) between provinces, from nearly -200 TWh in Shandong to +260 TWh in Inner Mongolia in 2023.[33] With market arrangements set separately by each provincial government, prices between provinces can vary significantly: prices in some eastern provinces were around 35% higher than in the northwest, in 2023.[34]

Around 20% of power consumed is transmitted interprovincially;[35] almost all of this occurs via long-term contracts. Constraints on cross-provincial trading contribute to the curtailment of renewable generation in high net power supply provinces, and to high prices in net power demand provinces. While VRE curtailment fell steadily over 2016-20, it has now begun to creep up again.[36] VRE deployment continues to grow rapidly, but if more output is curtailed due to infrastructure or market constraints, this could delay reductions in costs and emissions.

A cluster of dampening feedbacks between variables related to the locational characteristics of the power system could moderate these effects.

[33] Per data from China Electricity Statistical Yearbook 2023.
[34] Per data collated and published by North Star Electricity Network (www.bjx.com.cn).
[35] Per data from CEC's 2023-2024 National Electricity Supply and Demand Situation Analysis and Forecasting Report.
[36] Per official data, yet international analysis suggests these data may understate the magnitude of curtailment.

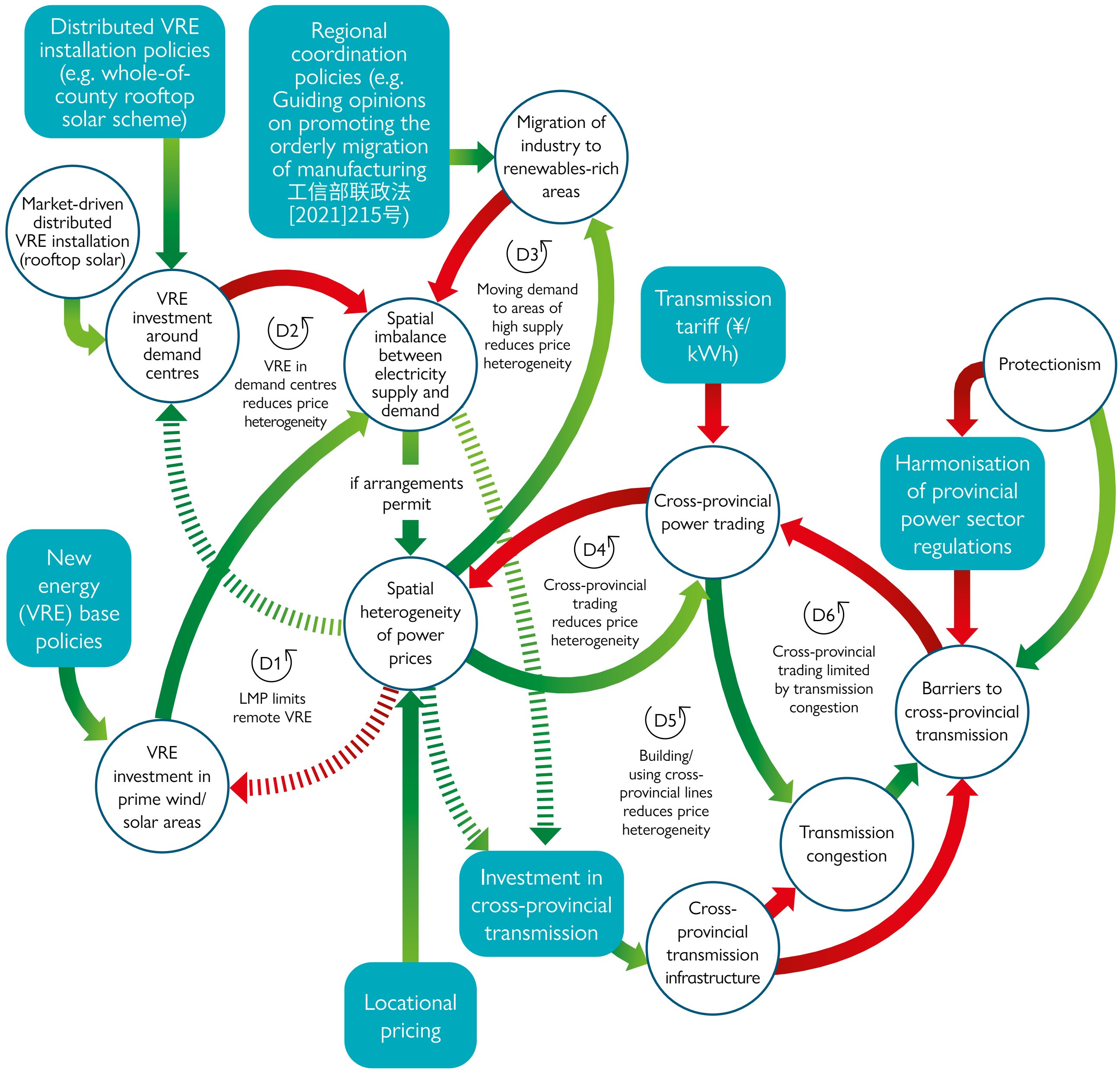

Figure 1-13: CLD of locational dynamics and prices.
Note: This submap shows the feedback loops and policies relevant to the location dynamics in the power sector. Green arrows indicate a positive relationship (i.e. factors move in the same direction) and red arrows indicate a negative relationship (i.e. factors move in opposite directions). A dotted arrow indicates a weak or conditional relationship. White nodes represent variables in the system. Blue rectangular nodes represent policy factors. The letter "D" denotes dampening feedback loops.

Figure 1-13 above shows four dampening feedbacks centred on the spatial heterogeneity of electricity prices, linking this variable separately with:

a) Cross-provincial power trading (D4). Larger price differences increase this trading, which reduces the price differences.

b) The migration of industry towards areas rich in renewable resources (D3). A greater price difference drives more industrial migration, which reduces the price difference.

c) Renewable power investment close to centres of power demand (D2). Larger price differences increase this investment, which reduces the price difference.

d) Renewable power investment in areas of prime renewable resources (D1). Larger price differences reduce this investment, which reduces the price differences.

As can be seen from the system map, a diverse range of policy interventions can strengthen these dampening feedbacks. Investing in transmission infrastructure and harmonising provincial electricity market regulations can enable more cross-provincial power trading. Reforming energy-based cross-provincial transmission pricing could also prove useful in this regard (IEA, 2023), but is not discussed in the current analysis. Industrial strategy can support the growth of industry in VRE resource-rich regions. Distributed renewable energy installation policies can increase investment in capacity close to demand centres. Importantly, these feedbacks reduce price disparities by addressing market fundamentals, in contrast to administrative price restrictions which tend to move economic problems from one part of the system to another without solving them (as when, for example, a cap on electricity prices combined with high input costs forces power plants to become loss-making).

The government's plan to develop a national unified electricity market system includes the aim of unifying market design principles across regions, which should help to enable more cross-provincial trading. Besides institutional reforms, investment in transmission capacity is crucial to leveraging the geographical advantages of VRE across China's landmass—such investment reached ¥608 bn in 2024 (a year-on-year increase of 15.3%).[37]

Until recently, spatial heterogeneity of pricing has existed only between provinces, while prices have not varied locationally within provinces. The development of spot markets, a central part of the market liberalisation programme, creates the possibility for variation of prices on a smaller geographical scale. The 2023 document *Basic Rules for the Electricity Spot Markets (Trial)*[38] allows provincial governments to choose between nodal, zonal, or system marginal pricing, in accordance with local grid structures and congestion levels. The Basic Rules instruct provinces with "severe" transmission congestion to opt for nodal pricing, those with "significant" congestion to opt for zonal pricing, and for others to adopt system pricing. So far, different provinces have opted for different models, with nodal clearing being the most common choice to date (implemented in several provinces plus the Southern Regional Spot Market). In principle, this choice for locational pricing within provinces should allow the dampening feedbacks shown in Figure 1-13 to operate at the local level as well as the interprovincial level, helping to keep electricity prices low as the transition to clean power progresses.

The UK's experience so far has been with whole system marginal pricing, with a single price across the entire country. As the deployment of wind power has increased, so has the regional imbalance in supply and demand, with surplus generation in the north of the country, and high demand in the south. The cost of transmission constraints is estimated to have increased from around £0.7 bn in 2018/19 to £1.8 bn in 2022/23.[39] Interconnectors between the UK and neighbouring countries have limited ability to ease these constraints, and instead sometimes worsen them, such as when UK electricity prices are higher than in Norway, resulting in additional supply coming into the north of the country, and lower than in France, creating additional demand (via exports) in the south.

As part of the REMA programme, the UK government is now considering a shift to zonal pricing, which it estimates could save in the region of £5-15 bn over the period from 2030 to 2050.[40] The advantages are seen not only in terms of incentivising investment in renewable generation to take place in areas where it is most needed—an effect likely to be limited by non-price factors such as resource availability, planning regulations, seabed leasing rights (for offshore wind), and grid connections. Increasingly, the opportunity is seen in terms of influencing the operation of assets, with plants incentivised to generate when supply is most needed in their locations, and interconnectors, storage, and demand-side response increasingly used to manage locational imbalances as well as temporal imbalances.[41] The main risk identified by UK policymakers is that by increasing revenue uncertainty, locational pricing could undermine investment in renewables, including by increasing the cost of capital (the option of nodal pricing was dropped for this reason, as well as for its complexity of implementation). Resolving this requires consideration of how locational pricing may interact with policies to support renewable investment, as outlined below.

[37] Per NEA data.
[38] NDRC and NEA (2023). Basic Rules for Electricity Spot Markets (Trial). 发改能源规[2023]1217号
[39] See National Grid ESO net zero Market Reform Phase 3 Conclusion March 2022.
[40] UK Department of Energy Security and Net Zero, 2024. Review of electricity market arrangements, second consultation document, p90.
[41] Ibid.

Locational pricing and CfDs

The new VRE CfD pricing mechanism introduced by *Document 136* in February 2025 has been compared, in this report and elsewhere,[42] to the UK's CfD (see Section 4.3). Among the key differences between the policies is the degree to which operational and investment signals, including locational price signals, are preserved.

Under the UK CfD, all generators are topped up to their strike price for every MWh they sell, regardless of where or when they produce it. This shields VRE investors from market price volatility and incentivises output maximisation. Site selection for VRE assets is therefore largely driven by the simple question of where output is likely to be highest; other factors such as transmission costs and system-level efficiency do not figure strongly in locational decisions. This has led to VRE investment concentrating in remote areas of high VRE resource potential, such as northern Scotland, creating large operational and investment inefficiencies. These market arrangements thus dull the dampening feedbacks presented in Figure 1-13 that would otherwise promote a more efficient spatial distribution of generation assets.

The CfD mechanism described by *Document 136*, however, does not entirely insulate investors from price risks and so may preserve these feedbacks, thereby encouraging assets to site in efficient locations. As outlined in Section 4.3, top-up payments under the *Document 136* CfD are calculated as the difference between the strike price and the average market price received by similar generators over the previous month; they are not calculated at the generator level as in the UK. Since the revenues received by VRE generators under this mechanism are the sum of monies from both market trading and the top-up payment, similar generators within the same province will not necessarily end up with the same earnings. While the top-up payment will be uniform, total revenue may diverge between generators based on differences in market-based revenues. For example, a solar PV generator located in an area with high nodal/zonal prices may earn higher market-based revenues than one in an area of lower prices, yet will still receive the same top-up as other solar PV plants based on the average price difference calculation across the entire province.

This arrangement means that locational price signals, if they are created by the zonal or nodal pricing models adopted in various provinces' spot markets, may be retained, giving developers impetus to consider location in investment decisions. While these locational signals may be weak at present, the increasing market participation of VRE and maturation of spot markets may strengthen them in the future. Therefore, while the UK-style CfD blunts signals to consider location in VRE investment decisions, the *Document 136* CfD is capable of preserving locational incentives. In theory, this could enable the dampening feedback loops in Figure 1-13 to operate, leading to a more spatially efficient layout of VRE assets.

5. Renewables surplus as an emerging challenge

5.1 Potential generating surplus and negative prices in the UK context

As noted in Section 2.3, with over a third of its electricity coming from wind and solar (in addition to at least 20% from inflexible baseload plants like large nuclear stations), the UK is now experiencing more frequent negative prices.

Brown *et al*. (2024) highlight the scale of the challenge in the UK: given the high ambition for renewables, they estimate that by 2030, nuclear, wind, and solar may together exceed demand (on an hour-by-hour basis) for roughly half of the day, on average.

Negative wholesale prices are driven by misaligned incentives for both generators on ROCs and those on early rounds of CfDs, which will bid negative in the wholesale market to secure their top-up payments.

[42] See reports by Sina Finance and People's Daily.

To remove the incentive for new generators to drive prices further below zero, the UK government changed the CfD rules in 2022 (AR4) to preclude new generators from receiving top-up payments to their strike price whenever the reference price (in the day-ahead market) is negative. Whilst this tackles the operational distortion, if and as growing periods of surplus do lead to more negative prices, this does, however, introduce more risk into the CfDs. Compensating for this risk presumably contributed to the higher CfD prices in the most recent CfD auction (AR6, 2024). This tension between investment efficiency and operational distortion, set off by negative prices, is one of the factors motivating the UK's current REMA process[43] and consideration of new approaches (summarised in Section 6).

5.2 Renewables surplus likely in China

In 2024, the wind and solar penetration, at 18.6%,[44] was about half of that in the UK, where VRE generated 36% of electricity.[45] However, provincial penetration levels vary considerably within China. The provinces most advanced in the transition are already experiencing penetration levels similar to, or higher than, that of the UK, such as Qinghai (44.8% in 2023),[46] Hebei, and Gansu.

Most provinces had a solar and wind share of generation in the range of 10-20% in 2023, substantially lower than that of the UK but growing on a similar trajectory (Walter, Bond and Butler-Sloss, 2024). The spread of results in Figures 1-14 and 1-15 below show how the frequency and magnitude of renewable surplus could vary widely between provinces in 2030.

Forecast of surplus renewable generation in China

For China, a modelling study carried out for this report by the Tsinghua authors using the RESPO (Renewable Energy Siting and Power system Optimisation) model developed by Tsinghua University aims to estimate how often the supply of renewable power will exceed power demand in 2030 in each province. The increasing frequency of surplus events poses significant risk to VRE revenues, both in terms of volume risk (some VRE generation will need to be curtailed) and price risk (regardless of specific pricing arrangements, prices during these events are likely to be extremely low, reflecting the real-time value of VRE generation in that moment).

Modelling method

To represent the frequency with which the output of renewable energy exceeds demand, we first calculate demand in each province. Two scenarios are considered: the first assumes zero interprovincial flows, whereas in the second scenario we allow for interprovincial transmission. In the second scenario, the supply of renewables is compared to the sum of provincial demand plus net exports. Then, after deducting generation from must-run technologies (including nuclear power and combined heat and power plants) and VRE output, we obtained the hourly residual power demand in 2030. It is acknowledged that negative prices may induce greater flexibility for nuclear and combined heat and power plants, but for the sake of simplicity, these plants have been assumed to be must-run. A value below zero indicates that over the course of the year in 2030, total renewable power generation is projected to surpass total demand. Data are from Zhang *et al.* (2024).

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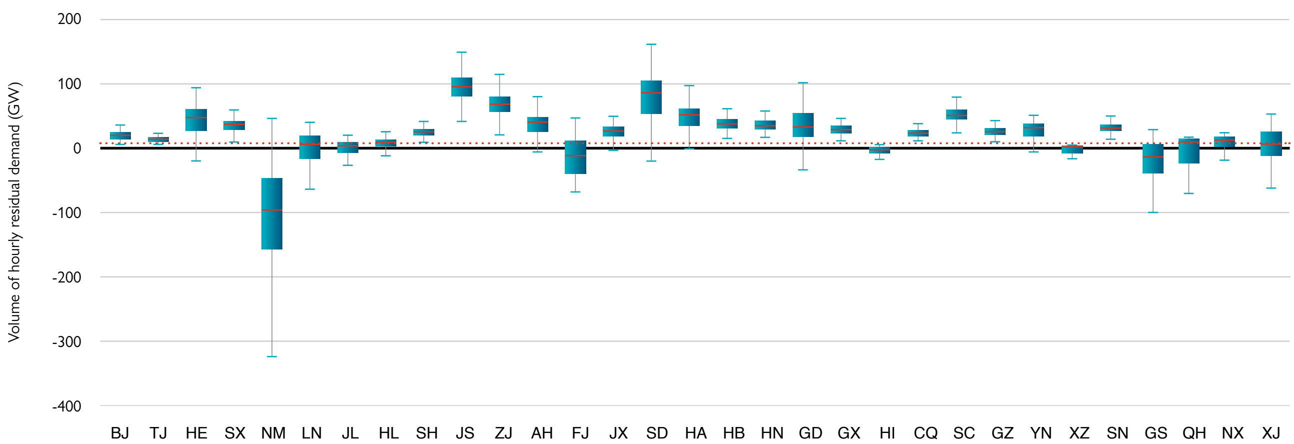
[43] Department for Energy Security and Net Zero (2025). Review of electricity market arrangements.
[44] Per statistics quoted by NEA officials.
[45] Per Ember Energy's Yearly electricity data.
[46] Per a 2023 report by Qinghai Energy Administration. Qinghai province clean energy development report.

Modelling results

Figure 1-14 shows that when interprovincial transmission is included, median residual demand is either close to zero or positive, for all provinces. However, many provinces are still projected to experience net negative residual demand for a significant proportion of the time.

Figure 1-15 shows the proportion of time in which the supply of VRE, nuclear, and must-run thermal generation is projected to exceed electricity demand in 2030 for each province, including simulations that both include and ignore cross-provincial transmission. It can be seen that interprovincial transmission greatly reduces the frequency of renewables exceeding power demand in power-exporting provinces, notably Inner Mongolia and Xinjiang, while increasing the frequency in some power-importing provinces, such as Beijing and Tianjin. Most importantly, these figures represent a substantial change compared to the situation at present. We project that nine provinces will experience frequent surplus generation events (in the range of 20-30% of the time) in 2030. This represents a significant volume risk, in addition to the price risk faced by renewables. Given the long payback period of VRE investments, this trend threatens to erode market-based revenues of VRE installed today.

(a)



(b)

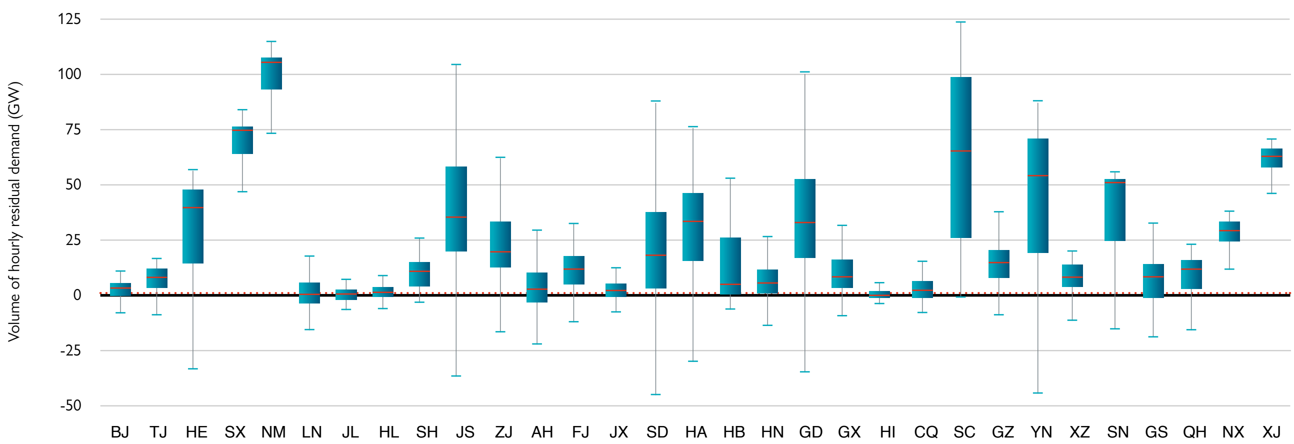


Figure 1-14: Residual load projections for each Chinese province in 2030.
Note: Each box represents 8760 data points for the residual loads during each hour of the year 2030. Residual load is calculated by subtracting VRE, nuclear, and must-run generation from total projected demand. Figure 1-14a assumes zero interprovincial flows. Figure 1-14b incorporates interprovincial transmission. Red lines are medians, boxes show interquartile range, and whiskers extend to the maximum and minimum values. A red dotted line at zero indicates a perfectly balanced supply and demand situation.

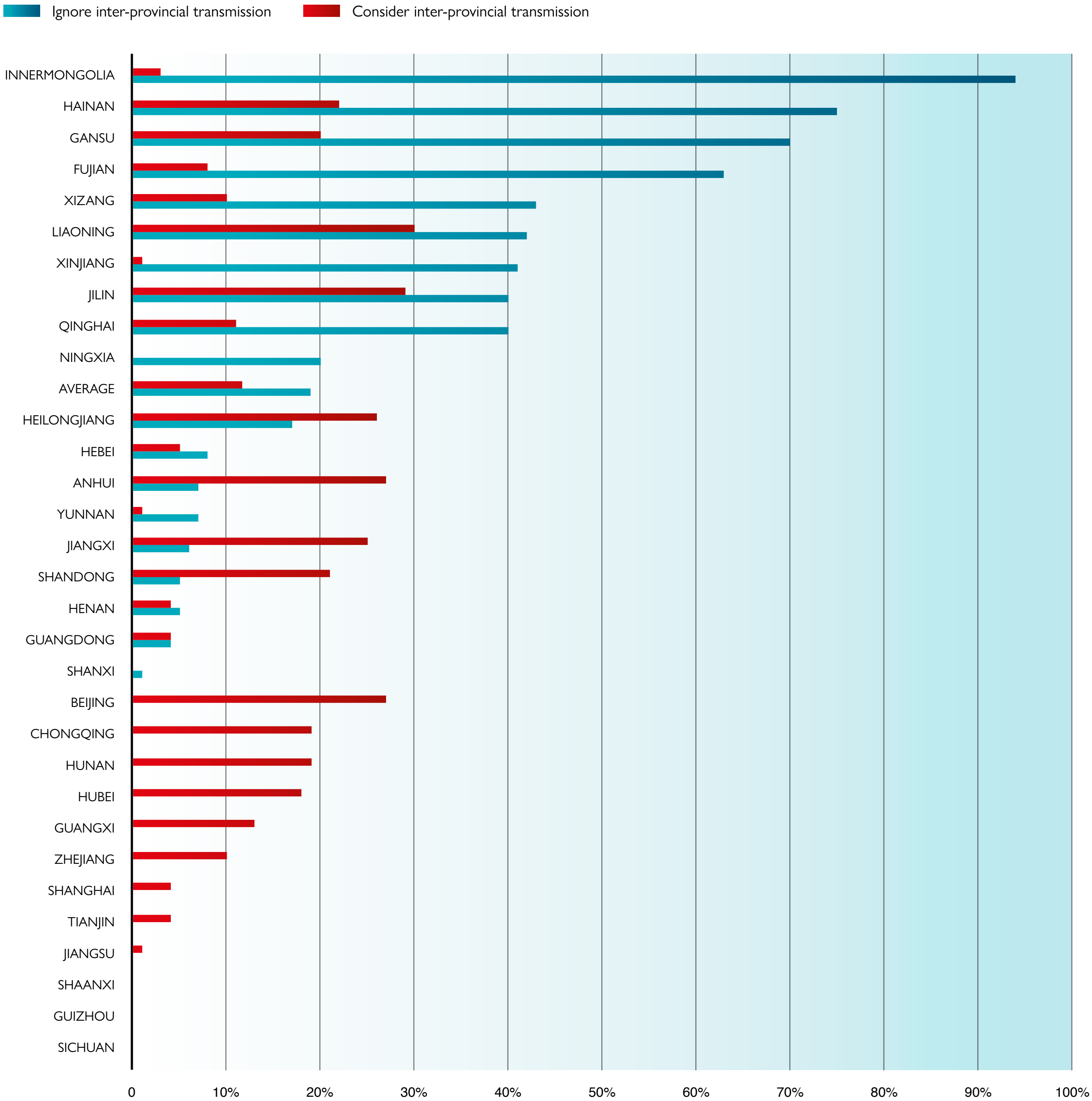


Figure 1-15: Prevalence of net negative residual load for each province in 2030.
Note: Residual load is calculated by subtracting VRE, nuclear, and must-run generation from total projected demand. Percentages along the x axis indicate the proportion of time that residual load is projected to be net negative. For example, a value of 20% indicates that for 20% of hours in 2030, VRE, nuclear and must-run thermal generation is expected to together surpass total demand..

6. Possible amendments to CfD design given potential surplus generation

6.1 Importance of flexibility

Faced with the prospect of growing periods of generation surplus from must-run baseload generation plus wind and solar, the best solution is to enhance flexibility on the power system. We discuss policy options to enhance deployment of flexible assets in Chapter 2.

Another important solution is enhanced interconnection. Figure 1-15 indicates our estimate of the extent to which utilising provincial trade can reduce the potential surplus in Chinese provinces with large renewables capacity and less demand; this could be substantially enhanced by expanding cross-provincial interconnection. In the UK, the scope for absorbing surplus generation from UK renewables is significantly increased by growing interconnection to the European continent, whilst ongoing expansion of connections across the European Union (EU) will also enhance the overall capacity to usefully absorb high VRE output.

6.2 Changes to CfD design

In 2022, the UK modified its CfDs to prevent renewables receiving top-up payments when the reference (day-ahead) price is negative. This reduces operational distortions but introduces some risk for investors. It may also be valuable for encouraging storage investment; holders of these CfDs have a strong incentive to prevent negative price events and find off-takers for their energy. This should, in theory, reward any investment in storage with the prospect of increasingly frequent opportunities to buy electricity when wholesale prices, if not negative, are extremely low.

In a fully liberalised system based solely on private finance, as in the UK, the question remains as to how much the CfD may alleviate perceived risks to investors, who may still choose not to build additional renewable capacity. The current CfD design largely removes price risk, but volume risk will remain, and depends on assumptions about how much storage or other flexibility may be developed, and when.

The UK government's REMA program is considering two more radical options to enhance investor confidence:

1. A "*deemed CfD*" in which the payment received by generators is linked to the "deemed" power generation of each asset—the maximum it *could have* potentially generated at any given time, instead of being linked to the actual volume of power generated. Revenue is calculated as follows:

$$R_{total} = R_{CfD} + R_{market}$$

R_{total} is the total revenue earned by a VRE generator (excluding earnings from ancillary service markets), R_{CfD} is revenue associated with CfD-related payments, and R_{market} is revenue earned via selling power on merchant terms.

Total revenue is thus the sum of CfD-associated revenues and those earned from trading in the wholesale market. This differs from the UK's current policy, in which VRE revenues are entirely delinked from market prices, with the exception of negative price events (see Section 2.2). Revenues from CfDs and the market are given by:

$$R_{CfD} = \sum Q_{deemed} \times (p_{strike} - p_{ref})$$

$$R_{market} = \sum Q_{actual} \times p$$

Q_{deemed} is the quantity that a generator is deemed to have been able to generate, and Q_{actual} is the actual volume of power generated and sold on the wholesale market. p_{strike} and p_{ref} are the strike and reference prices, respectively. p is the market price, and is thus functionally equivalent to p_{ref} in this example.

The "deemed" power generation quantity would be estimated through site-specific data on asset capacity, weather, and any other relevant factors. This removes price and volume risk related to potential renewable surplus events. The deemed CfD effectively breaks all three of the dampening feedbacks (Figure 1-10) that threaten to undermine renewables investment. In principle, actual generation could instead respond more flexibly to real-time system requirements, reducing balancing costs and potentially opening the door to increasing ancillary service market revenues.

In practice, these benefits may be more difficult to realise in the Chinese power system, at least as it currently operates. The benefits of enhanced operational efficiency will only be possible if clear price signals are sent through spot markets, yet these remain underdeveloped in almost all provinces. In addition, VRE generators are currently unable to directly participate in the ancillary services market. Conversely however, the most obvious drawback of the deemed CfD—paying renewables even for output that cannot be used—may be lower in China than in the UK due to projected future demand growth.

2. Alternately, a **capacity-based CfD** would provide a fixed payment based on a VRE asset's capacity. The revenue would be de-linked from generation, and so insulated from any price or quantity risks. Its operation would be entirely driven by market incentives, which should tend to support system flexibility and operational efficiency. Revenue is calculated as follows:

$$R_{total} = R_{CfD} + R_{market}$$

As with the deemed CfD example above, R_{total} is the total revenue earned by a VRE generator (excluding earnings from ancillary service markets), R_{CfD} is revenue associated with CfD-related payments, and R_{market} is revenue earned via selling power on merchant terms. Revenues from CfDs and the market are given by:

$$R_{CfD} = C \times p_{strike}$$

$$R_{market} = \sum Q \times p$$

C is the CfD-backed generator's capacity (in MW), and p_{strike} is the strike price. Q is the quantity of power generated and sold on the wholesale market, and p is the price at which it is sold.

In this model, the CfD would provide generators with a regular, fixed payment based on their installed capacity (¥ or £/MW). Beside their CfD-associated revenues, however, generators could also operate in markets on merchant terms. This would promote efficient operational decisions as generators seek optimise their trading strategies, but would expose generators to a degree of volume and price risk on a day-to-day basis.

With a capacity-based CfD, the optimal share of VRE revenues paid from the fixed capacity payments (relative to the share from market activity) could in principle be revealed through auctions to award the capacity payments. The three dampening feedbacks shown in Figure 1-10 would be weakened, but not eliminated, as generators would still sell earn variable revenues by selling power on the wholesale market.

At the time of writing, the UK is yet to decide between the options of maintaining the current CfD design or choosing one of these two other options, noting some additional variations.[47]

Unlike the UK, where power sector policies are almost always implemented nationally,[48] China often takes advantage of the diversity of its provinces to pilot different approaches. An example is the freedom for provinces to choose between whole system, zonal, or nodal pricing within the new spot markets, as discussed in Chapter 3. Given the significant uncertainties around how effectively CfDs will support continued renewable investment in future, there could be advantages to allowing provinces to test different approaches, including the standard CfD, deemed CfD and capacity-based CfD designs.

[47] Notably, Newbery (2022) proposed a 'yardstick CfD' which combines two elements: payment based on day-ahead forecast rather than actual output, and strike prices guaranteed for a total output, rather than fixed time.

[48] In fact, this is true for Great Britain; there are different arrangements in Northern Ireland.

7. Conclusions and recommendations

In this chapter, we analyse the primary risks facing VRE investment in China under market-oriented reforms, including low electricity price risk, revenue volatility risk, and volume risk associated with surplus events. Using causal loop diagrams, we elucidate why these risks are likely to increase over time, and why the existing GEC system may not adequately incentivise VRE investment in this context. Drawing on decades of experience from the UK's electricity market framework, we propose recommendations for designing differentiated CfD mechanisms to mitigate investment risks and advance renewable energy investments.

Notably, this study was initiated prior to the official release of policy *Document 136*, with research frameworks completed during its formulation phase. We also shared our preliminary findings with policymakers that participated in the development of *Document 136*. Analysis of *Document 136* reveals strong alignment between our recommendations and the policy's guiding principles in the following key areas:

1. **Support for CfDs:** This chapter has already clearly addressed the use of CfDs to incentivise VRE investment in the context of market liberalisation (Sections 3.2 and 6.1). It is consistent with the price settlement mechanism for the sustainable development of new energy, which is essentially a CfD, in *Document 136*.

2. **Long contract coverage:** Past power market mechanisms lack stable long-term price guarantees for renewables. Section 4.1 advocates multi-year CfDs, and *Document 136* states that the duration of CfDs should match investment payback periods, ensuring stability in VRE revenues over a time scale meaningful to investors.

3. **Market-based strike prices for CfDs:** Our recommendation for market-based strike price formation (Section 4.2) matches *Document 136*'s new competitive pricing mechanism.

Document 136 promotes the full market-based formation of on-grid electricity prices for VRE. The release of this policy is a crucial step in advancing China's power system reform. However, as a national document, it remains quite vague regarding specific implementation details. There are still many issues that need to be clarified and refined at the provincial level, including:

1. **Multi-tiered planning and coordination.** Although *Document 136* requires provinces to align renewable development targets with the national plans, it does not clearly state a mechanism to ensure this alignment. Furthermore, since the CfD arrangements deal with generation metrics, not capacity, it remains unclear as to what role the new mechanism will play in promoting VRE investment in the context of national installed capacity targets.

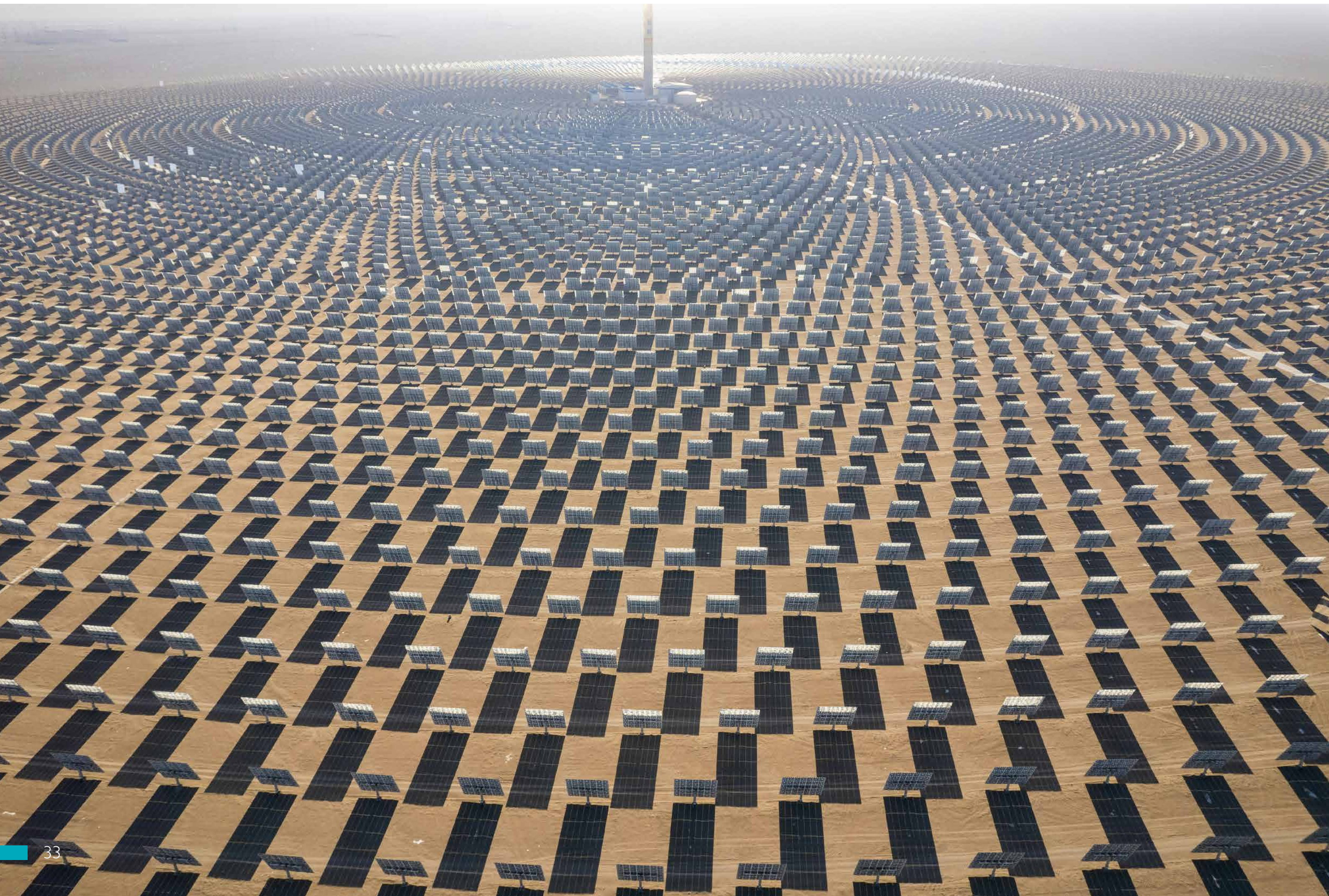
2. **Coordination with GECs.** *Document 136* states that generators will not receive income from GECs for the electricity volume included in the new CfD mechanism. Therefore, there remains uncertainty regarding the management of the GEC (and RPS) scheme and how they will be linked to the new pricing regime.

3. **Negative price management.** The *Document 136* mechanism does not specify processes for handling negative electricity prices. Following experiences in the UK, we recommend that if zero electricity prices or negative electricity prices continuously occur for a long time in the spot market, CfD difference payments should not be paid.

4. **Mechanisms to incentivise energy storage deployment.** The policy abolishes a mandate that previously required VRE generators to install energy storage, but it does not specify future options to incentivise the development of energy storage through market mechanisms. This issue be further discussed in Chapter 2.

5. **Cost allocations remain opaque.** Per *Document 136*, the CfD settlement payments to generators will be incorporated into system operation fees, the bulk of which are currently charged to commercial and industrial users. However, it remains unclear whether the fees should be wholly or partially borne by users, and it is also not clear which types of users should bear these fees, which may lead to questions regarding fairness.

The CfD policy created by *Document 136* addresses price risk but not the volume risk faced by renewable generators. Our analysis suggests that volume risk could become significant in China within the next five years, especially in provinces more advanced in the transition, and this could quickly become a negative influence on investment decisions. We recommend addressing volume risk both by accelerating development of flexible demand sources to encourage offtake for VRE that would otherwise be curtailed (see Chapter 2 for more on flexibility), and by experimenting with different CfD designs, including deemed and capacity-based CfDs, across China's provinces, with the results monitored and compared to inform future policy decisions.



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Chapter 2
Maintaining security of supply in the context of technological change

Authors: **Da Zhang, Jian Han, Ying Zhou, Yang Qu, Max Collett, Michael Grubb, Simon Sharpe, Katrina Salmon**

Contents

1. Context

Penetration of VRE—wind and solar—in China reached 18.2% in 2024,[1] and is expected to grow to 65-70% by 2060[2], when the country aims to achieve net zero. This growing penetration of VRE raises two major challenges for the Chinese electricity system.

First, the rapid growth of VRE reduces operation of other plants, and particularly coal-fired units. Given that coal-fired generators have traditionally earned revenues through electricity sales, declining load factors may undermine the economic viability of new and existing plants without other support. This creates the risk, or at least the perceived risk, of premature shutdowns of coal plants leading to insufficient dispatchable capacity during periods of low VRE generation and potentially threatening grid reliability.

Second, higher penetration of VRE, and particularly solar, requires stronger operational flexibility across the system: flexible generators will need to ramp up and down faster and more frequently to accommodate variable generation (see Figure 2-1). China's small deployment of natural gas will further complicate the ability to balance the system as compared to the UK.

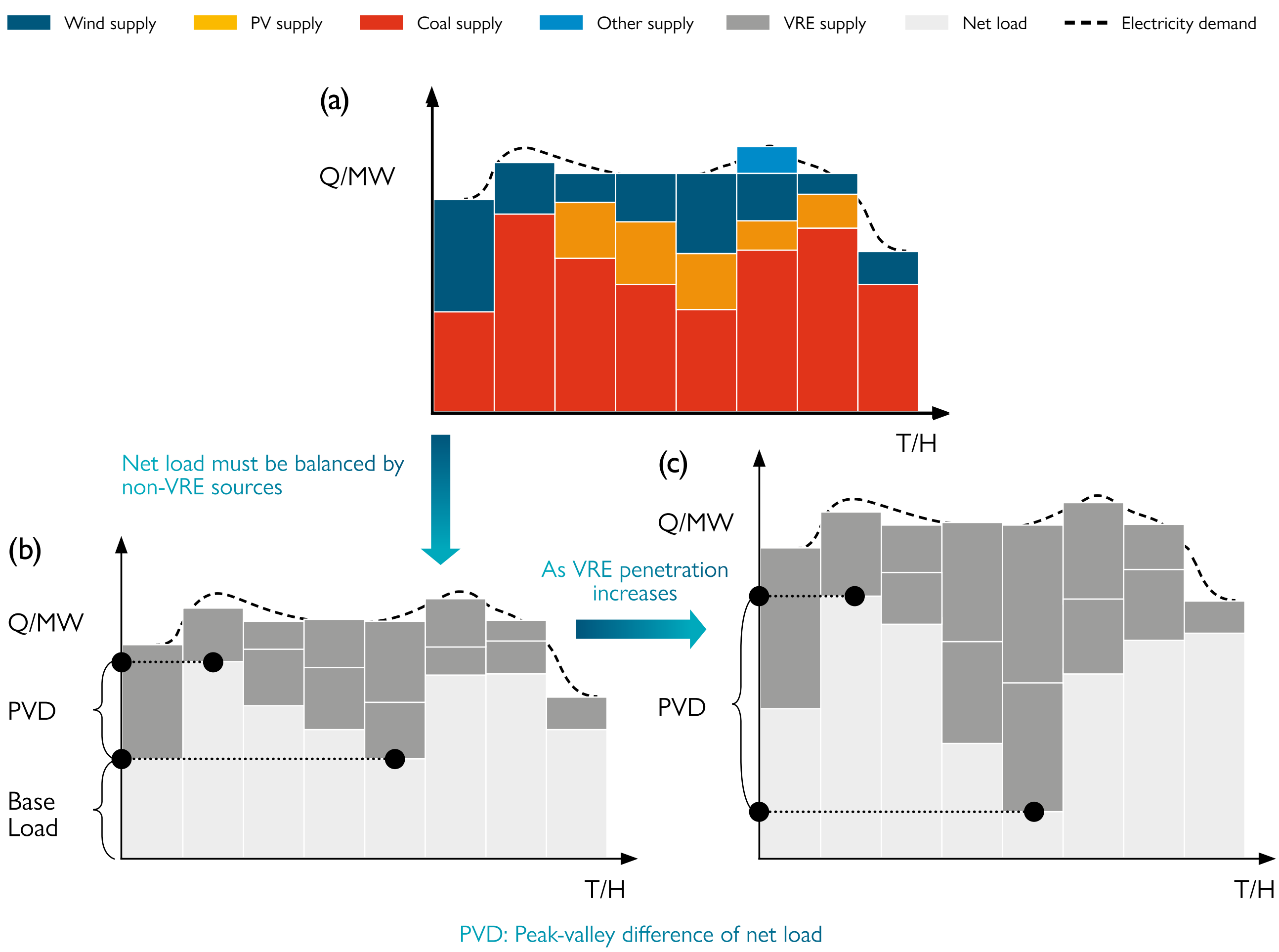


Figure 2-1: Trend in net load peak-valley difference amid growing VRE penetration.
Note: A typical daily dispatch mix and load curve is shown in (a). The net load in this scenario is highlighted in (b), along with the daily maximum and minimum net loads to show peak-valley difference. Over time, as both demand and VRE penetration increase, the peak-valley difference is expected to widen, as shown in (c).

China's solution to the first problem, to date, has been to introduce fixed payments for coal power capacity, as described in Section 2.1. While this may shore up thermal plants' economic viability for now, this approach risks introducing tension between the goals of security and decarbonisation, and does little to respond to the second problem given the flexibility limitations of coal-fired generators. Another approach has been to retrofit coal plants to increase operational flexibility.[3]

This chapter responds to these two challenges by first contrasting capacity remuneration mechanisms in China and the UK, then discussing policy mechanisms to support flexible low-carbon generation in the form of short-duration energy storage. Following this, we consider more closely options for maintaining security of supply while reducing or eliminating the need for investment in new coal plants including improving regional connectivity, deploying long-duration energy storage, and reforming the Emissions Trading System (ETS) to incentivise a stable phase-down of coal-fired power.

1 See National Bureau of Statistics (2025). People's Republic of China national report on economic and social development 2024. Note that this annual statistic includes distributed (rooftop) solar and wind. Monthly datasets often do not, which can lead to issues of underestimating VRE penetration, as noted in Myllyvirta (2024). Analysis: Monthly drop hints that China's CO_2 emissions may have peaked in 2023. Carbon Brief.

2 Per projections in Tsinghua University (2024). Technology Outlook on Wind and Solar Power Towards China's Carbon Neutrality Goal.

3 NDRC and NEA (2024). Coal power low-carbon transition upgrading and building action plan (2024–27). 发改环资[2024]894号

2. Capacity payments and capacity markets

2.1 China's experience with coal power capacity payments

A capacity payment scheme for coal (and gas) power plants was launched in 2024 to address concerns that declining operating hours would threaten generators' financial viability.[4]

Under this mechanism, coal power plants are paid a monthly flat rate based on their capacity, independent of generation. The payment is set at a level designed to enable the recovery of a certain percentage of generators' fixed costs (assumed to be ¥330/kWh/year): 30% in most provinces and 50% in provinces making faster progress on decarbonisation. By 2026, this proportion is to rise to at least 50% in all provinces. The cost of the payment scheme is recovered via industrial and commercial user tariffs. The policy states that generators must meet environmental and flexibility requirements to be eligible for the payments, but information on what these comprise in practice has not yet been specified.

Whilst this mechanism may shore up financial viability of the thermal power sector, there are several potential drawbacks to this approach.

First, this scheme singles out incumbent technologies, excluding other potential sources of capacity, such as new-type energy storage and demand side response. This promotes lock-in, rather than supporting emerging technologies that may have lower emissions and costs. Some provinces (e.g. Shandong and Zhejiang) have piloted capacity payments for battery energy storage systems (BESS), yet these localised efforts remain fragmented and lack standardised implementation frameworks.

Table 2-1: Coal-fired power capacity payments, by province (2024-25).

Provinces	Capacity Price (CNY/kW/year)	Provinces	Capacity Price (CNY/kW/year)
Beijing	100	Hubei	100
Tianjin	100	Hunan	165
Hebei	100	Guangdong	100
Shanxi	100	Guangxi	165
Inner Mongolia	100	Hainan	100
Liaoning	100	Chongqing	165
Jilin	100	Sichuan	165
Heilongjiang	100	Guizhou	100
Shanghai	100	Yunnan	165
Jiangsu	100	Xizang	100
Zhejiang	100	Shaanxi	100
Anhui	100	Gansu	100
Fujian	100	Qinghai	165
Jiangxi	100	Ningxia	100
Shandong	100	Xinjiang	100
Henan	165		

[4] NDRC and NEA (2023). Notice on establishing a coal power capacity price mechanism. 发改价格[2023]1501号

Second, the scope and scale of payments are not calibrated to planned capacity needs, risking overpayment by supporting more capacity than is actually needed. This seems likely under current arrangements, given that all coal plants receive payments. This differs from capacity markets, where system operators can set capacity targets then use auctions to meet them at the lowest cost.

Third, the flat payment mechanism cannot discover the market price that generators are willing to accept to provide capacity, again risking overpayment and inefficiency.

Fourth, despite aiming to ensure thermal generators' financial viability in the face of reduced operation, the payments do not actually incentivise this shift to a back-up role, and if anything, do the opposite. Flat payments mean that coal power plants are still encouraged to generate when it is profitable to do so. This would not be an issue if the profitability of generating at a given time reflected real-time system needs—as might be the case if spot markets sent clear and accurate price signals. However, few provinces have fully operational spot markets at present, and as such, the operation of coal assets is not responsive to real-time supply and demand trends. The flat payments also do not guard against situations in which high marginal costs of generation create loss-making conditions, as was the case in the 2021 blackouts. Furthermore, subsidising coal power revenues through capacity payments may lead to generators bidding below their marginal cost in MLT and spot markets, creating price distortions and squeezing renewables' revenues.

Finally, the payment scheme strengthens the business case for new coal power capacity additions and delayed retirements, which risks sinking capital into polluting assets that may become stranded. Financial analysts responded to the coal capacity payment policy with calls for the revaluation of coal power plants to reflect their improved financial situation.[5] Indeed, the aim of the scheme is to ensure the financial viability of coal power plants in the face of low capacity factors, preventing asset stranding. This entrenches the financial interests of SOEs and local governments in prolonging the operating life of thermal power assets, which could compromise efforts to achieve national climate targets.

These five issues suggest that the coal power capacity remuneration mechanism is an inefficient means of promoting capacity adequacy, and risks unnecessary expansion, or delayed retirement, of polluting coal power assets.

Strategically, the policy risks being in conflict with the government's goals for carbon peaking and carbon neutrality. Specifically, the capacity payments to coal plants also have an offsetting effect against the emissions trading system. Less efficient coal plants are paying around CN¥2.9 million per year in the emissions trading system, at the same time as receiving around CN¥27 million per year in capacity payments. This offsetting relationship risks making both policies less effective than they could be. This is discussed further in Section 5.7.

The policy reflects the overriding need for security of supply, however, so the rest of this chapter explores the many dimensions and policy options for sustaining security of electricity supplies in a world of rising renewables, starting with a review of the UK approach to security with some lessons from its experience with a capacity market.

2.2. The UK's experience with a capacity market

2.2.1. Context on the UK capacity market

For at least fifteen years after privatisation of the electricity system in 1990, the UK had no concerns about generating capacity adequacy. This was partly because it inherited a system with some existing surplus capacity. Indeed, concerns about overbuild by the former Central Electricity Generating Board (CEGB), typical of many state-owned enterprises, was one of the reasons given for privatisation.

By 2000, however, the market transitioned to a self-dispatch energy-only market, which required abolishing capacity top-ups, as there was no longer a single pool price on top of which these payments could be added. The transition was also accompanied by a complex balancing mechanism to ensure short-term operational sufficiency. This created a clear incentive to vertical integration for retailers and generators to ensure they were protected both ways against electricity price uncertainties. This, in turn, created major barriers to entry, and a perception—at least—of the electricity system as an oligopoly of major power companies controlling the entire system from generation to consumption.

5 For one example, see Huafu Securities (2023). Capacity prices are expected to be implemented, the long-term value of thermal power should be reassessed.

Given the absence of any capacity payments, there was little incentive for these companies to build more generation (as this would depress the wholesale price, and peak pricing in particular, which was their main source of revenue). This further compounded unease about implications of the market's design, and in the context of trying to phase out coal to meet climate targets, started to raise fears that the system would run short of capacity.

Consequently, the 2014 Electricity Market Reform introduced a capacity mechanism (CM), soon known as the capacity market to emphasise its use of competition to secure system security at minimum cost. The mechanism involves companies bidding for contracts that provide minimum guaranteed income (of various durations) for plants able to generate when called upon by the system operator during periods of system stress. Plants receive monthly payments regardless of how often they are called upon, but if they are not available when required, they may be penalised.

After considerable debate, the CM was set up as a whole-system mechanism, with all generators eligible to bid, except for those on other support contracts (such as CfDs). Part of the reason for this was to avoid complications of existing generators closing down, and then seeking to bid as new entrants. Consequently, the vast majority of bids awarded go to existing generators. Over time, the scope of eligible technologies has been adjusted to exclude some options (e.g. small diesel generators), and include others (e.g. some industrial demand-side response).

Two auctions are held annually, one awarding four-years-ahead contracts (T-4) and the other awarding one-year-ahead contracts (T-1). The former was designed to facilitate companies' operational and financial planning, including investments in new capacity. The latter (T-1) auction enables near-term adjustments to match needs, including for options with shorter lead times like batteries and DSR, and deferring premature plant closure, if the capacity is deemed to be needed. These auctions are additive: the total de-rated capacity guaranteed by the mechanism is the sum of the T-4 auctions before and the T-1 from the previous year, the latter thus also giving flexibility for the system to adjust to recent trends. The design includes 15-year contracts for new build, 3-year contracts for refurbished capacity, and 1-year contracts for existing capacity.

Based on technical advice from the system operator, the government ultimately decides the demand curve used to determine the amount of capacity to procure at a given price. One clear risk of any capacity mechanism is the incentive for politicians and regulators to request more capacity than really needed—no one wants to be held responsible for any risk that the lights go out (Newbery and Grubb, 2015; Grubb and Newbery, 2018). This implies a potential bias to over-procurement, which would drive up the price and increment payments to all generators at the expense of consumers.

To reduce this risk, the advice of the system operator is scrutinised by an independent Panel of Technical Experts (PTE), which publishes an independent annual report on the UK capacity needs, and the extent to which these can be met by existing and expected new capacity. One issue that emerged was the potential 'latent capacity' existing on the system, physically able to keep the lights on if needed, but not normally participating in system operation (such as on-site back-up generating capacity in many industrial and commercial facilities), and other elements of potential demand-side response that remained largely neglected.

Since no power plant is 100% reliable, to reduce the contrary risk of capacity under-procurement, different types of generators are weighted (by de-rating factors) according to expected statistical availability. Assessing the relative contribution of different sources to security is the other important role of the PTE.

In the UK, interconnectors to other countries are treated much like power stations in terms of their contribution to security of supply. This is true to the extent that the UK is confident to rely on imports when required. On this basis, after the CM's first year, interconnectors to other countries were included in the auctions. Each interconnector has separate de-rating factors applied, according to the degree of correlation between the connected electricity systems, to better estimate the likely capacity available to the UK in a stress event.[6]

2.2.2. Current functioning of the CM

When first launched, the CM had been expected to support the construction of a new generation of gas plants (combined cycle gas turbines—CCGTs), at a capacity cost of around £50/kW/year (Grubb and Newbery, 2018). In practice, the auction clearing price for many years was much lower (Figure 2-2) – below £20/kW/year for the first seven delivery years. Only one CCGT was awarded a CM contract, and that project did not proceed to construction.

[6] More detailed information on how the CM operates can be found here: DESNZ (2025). Capacity Market. See also Low Carbon Contracts Company (2025). Capacity Market (CM).

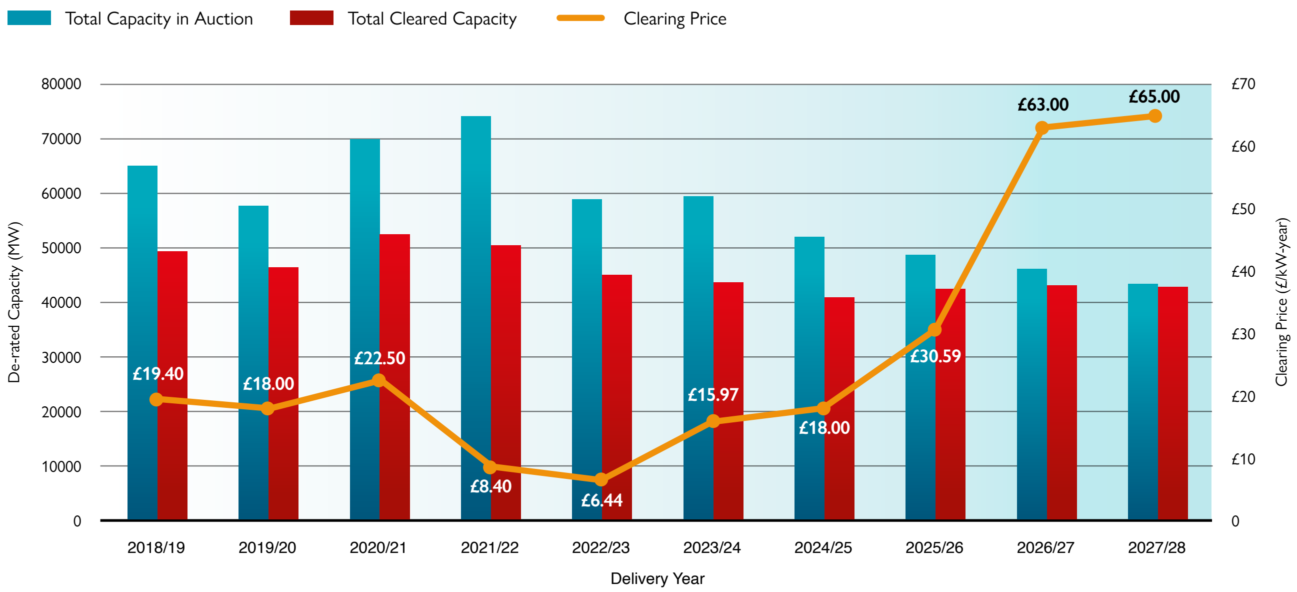


Figure 2-2: Historical overview of T-4 and T-1 auctions.
Source: Ofgem, 2024a.

Instead, the most recent T-4 auction primarily secured existing gas, interconnectors, and pumped hydro storage (Figure 2-3). The T-1 auction procured primarily existing gas and nuclear capacity, along with some demand-side response (DSR)[7] and new-build batteries (Figure 2-4). In the UK context, new coal was not competitive, and the carbon price made it more economic to run gas plants than existing coal. The price required to meet the capacity needs never rose high enough to maintain the economics of existing coal plants, as rising renewables output displaced the need for them as bulk energy providers; the UK's last coal plant closed in September 2024.

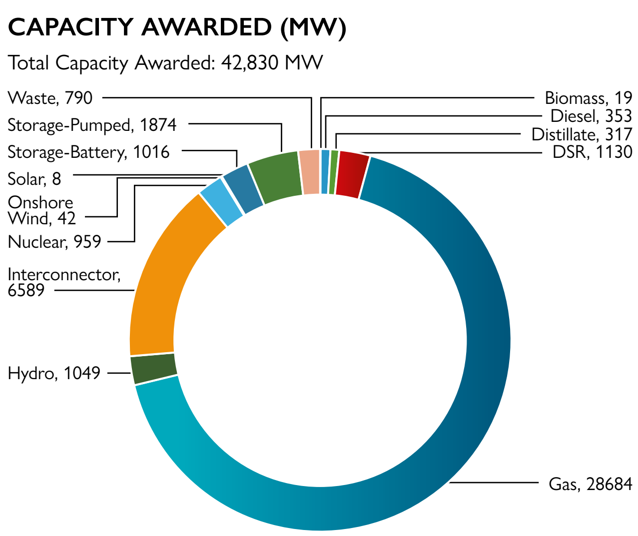


Figure 2-3: Capacity awarded in the 2024 T-4 auction by primary fuel type.
Source: National Grid ESO, 2024a.

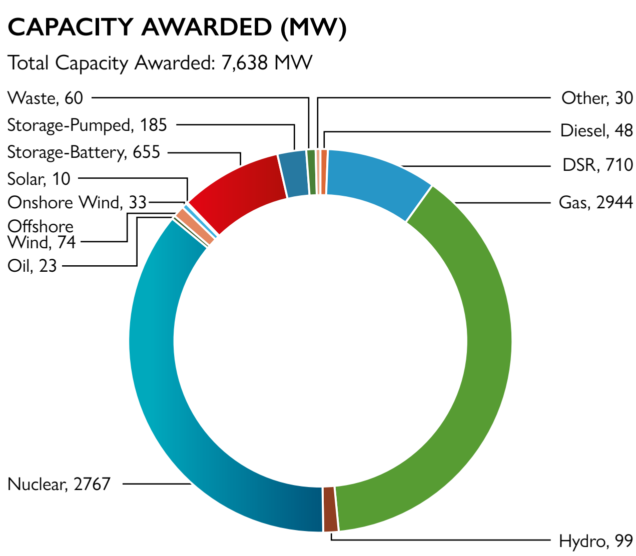


Figure 2-4: Capacity awarded in the 2024 T-1 auction by primary fuel type.
Source: National Grid ESO, 2024b

[7] Despite attempts to modify the CM rules to better enable DSR participation, such capacity has remained limited. Understanding and adhering to CM rules can be rather costly, and consequently only large industrial DSR has participated. Additionally, CM participants must prove their ability to provide capacity through periodic tests; for DSR participants, such tests represent foregone revenues, disincentivising participation.

In recent years, the clearing price of CM auctions has started to rise from the low prices seen when the mechanism was first launched (Figure 2-2). The recent increase in clearing price reflects declining liquidity and the need for new capacity to provide security, pushing auction prices high enough to justify building new capacity (Holness-Mckenzie, 2024). Rather than supporting new CCGT, however, most of this new-build capacity has come from BESS. The CM provides a valuable underlying revenue source for this technology, as 94% of British BESS capacity participates in the CM.

2.2.3. Future challenges and reforms

The government designed the CM to deliver reliable generating capacity at the cheapest price, given existing conditions. That is exactly what it has delivered, including helping to deploy low-cost BESS as outlined in the next section. New issues arise from year to year, which has led to a process of continued adjustment.

Early CM auctions procured significant diesel capacity. In principle, these plants were rarely called upon, having mostly high running costs, appropriate only to meeting extreme system needs (Grubb and Newbery, 2018).[8] Politically, being seen to subsidise carbon-intensive diesel power generators was highly problematic, and the auction rules were adjusted to bar diesel on environmental grounds.

The scale of BESS success in some of the early auctions was largely unexpected. Initially there were no constraints on duration, and much of the BESS capacity secured in early auctions had durations much shorter than the potential length of stress events. After considering minimum duration requirements, the alternate route has been to use the de-rating factors to deter very short duration batteries; the de-rating factors for 1-hour BESS have been reduced over time from 96% in 2017 to 19% in 2023, reflecting the fact that additional very-short-duration storage now adds little to security.[9] There is still a gap, however, as the CM does not provide sufficient revenue to support the development of novel long-duration energy storage (LDES) technologies. The Department of Energy Security and Net Zero (DESNZ) (2024b) is currently in the process of implementing a revenue cap-and-floor regime to ensure sufficient provision of these technologies (see Section 4.2).

The deployment of increasing quantities of VRE requires a broad re-assessment of what it means to ensure security of electricity supply. The current CM design is technology neutral, treating all generators' capacity as equivalent once de-rating factors have been applied. Yet, as VRE penetration grows, greater flexibility and faster response times are needed to ensure the system remains secure. To date, the approach in the UK has been to utilise multiple mechanisms for the different functions, notably, with auctions for such ancillary services.

However, given the need for multiple roles and durations for storage, and the need to provide security increasingly with zero-carbon options, there is need for continued innovation. As decarbonisation has progressed, the CM's continued support of gas and the absence of low-carbon longer duration storage have emerged as key hurdles. It remains unclear whether a single undifferentiated capacity market is appropriate, and the government is considering options including 'windows' within the CM as indicated below.

2.3. Common challenges and the future of capacity mechanisms

In China, given the multiple drawbacks of the current policy of coal capacity payments, one obvious alternative would be to adopt or experiment with a capacity market, as has been flagged in Chinese policy as early as 2021.[10] In general, the UK capacity market has been seen as a success, and capacity markets have been increasingly adopted internationally, though some common challenges remain.

In the Chinese context, government (potentially at provincial or regional level) could set capacity targets to guide auction processes, which could lessen (but not eliminate) risk of overpayment for surplus capacity. Payments could be linked to actual performance and availability, incentivising generators to provide the capacity they have committed to, which the current mechanism does not. The introduction of market competition for capacity payments would allow

8 Reciprocating engines are typically costlier per kW than open cycle gas turbines.

9 To account for duration limits when calculating the contribution to security of supply, the revisions use an Equivalent Firm Capacity metric (EFC), defined based on the question 'for a given penetration of that resource, what is the amount of perfectly reliable infinite duration firm capacity it can displace while maintaining the exact same reliability level?' (National Grid, 2017). These values will continue to decline over time, especially for BESS, as more storage comes into the system, which has been explored by Holness-Mckenzie (2024).

10 See NDRC (2021). Notice on further deepening market-oriented reform of on-grid pricing for coal-fired power. 发改价格[2021]1439号

capacity adequacy requirements to be satisfied at lower cost. This benefit would be enhanced if capacity markets were open to different technologies, including flexible low-carbon generation and storage. This would broaden the scope of competition and encourage the emergence of additional options, including distributed resources and demand-side responses, which tend to receive little attention from large centralised utilities.

If battery storage were included (considered in the next section), its capacity value would need to be expressed through a de-rating factor. This would require close attention to both storage duration, and also provincial context—a few hours of storage may be able to reliably bridge daytime PV generation to peak demand in solar-dominated systems, whereas other regions may need to bridge longer periods of very low VRE output.

It remains unclear the extent to which new technologies would be able to compete successfully against coal plants in a single, undifferentiated capacity market in China. Economically, the case for a single competitive auction is strongest for developed technologies, with broadly similar benefits and security characteristics; competition between coal, gas, and pumped hydro, for example, perhaps along with distributed technologies and other forms of latent capacity[11] that remain largely neglected for their security contributions. In the context of decarbonisation, the success of such auctions in terms of their selection of low-carbon technologies would also hinge on having an effective carbon price.

However, given the wider challenge of a rapid energy transition, a fully technology-neutral approach may be unsuitable (especially in the absence of an adequate carbon price). The REMA process has explored the idea of separating technologies into auction categories along two dimensions. One dimension is operating characteristics, such as response time, duration, and location in the context of transmission constraints and interconnector availability (DESNZ, 2024e). The other dimension concerns carbon intensity, and the need for extensive innovation—the issue which drove the UK to create multiple auction pots for CfD auctions. Undifferentiated auctions carry an inherent risk of favouring incumbent, mature technologies.

In the UK, if this reform is implemented, different clearing prices and minimum procurement targets could be introduced for operating characteristics or carbon intensities— essentially creating different "windows" within a single auction. Introducing different windows would allow the government to establish more refined criteria for the types of capacity it determines appropriate to prevent system outages (in the context of the energy transition). However, the details of how this mechanism may function are still being debated, given the benefits of competitive auctions in terms of technology pluralism, price discovery, and minimising political interference.

In China, given the dominance of coal, one option could be to replace the current coal payments by a capacity market with a window for coal (perhaps competing with pumped hydro as the other established technology). Given the current state of the Chinese ETS with free allocation (see Section 5.1), there could be a clear case to include criteria or incentives relating to plant energy efficiency or carbon intensity, alongside capacity and cost. This could reinforce the effect of the emissions trading system, instead of offsetting it, encouraging a shift towards the most efficient coal plants. Flexibility technologies, including energy storage, demand-side response, and virtual power plants, could compete for capacity payments in a separate auction window with different criteria. Comparing the prices at which each auction window clears would then at least provide some information on relative costs.

Decisions regarding the degree of technology competition to be built into capacity market auctions must weigh up the trade-offs of different options. As mentioned, there are benefits to fully competitive capacity auctions in terms of lowest-cost procurement, price discovery, and minimal administrative interference. However, in the context of China's technology transition, the lack of a meaningful carbon price, and the incumbent inertia of the country's coal power sector, it is likely that creating separate windows for technologies at different stages of development would provide more opportunities for nascent technologies to scale up, forming the necessary building blocks of a low-cost, low-carbon power system. As the energy transition progresses and technology costs evolve, auction design could be modified to introduce more or less technology competition, either by changing the number of windows or by moving technologies between windows.

In the UK, with no more coal plants operating, the CM continues to support a large quantity of gas capacity (see Figure 2-4). To reduce the amount of gas supported by the CM, REMA reforms may include placing emissions limits on future auctions, as practised in the EU capacity market. This could encourage the retirement of older, less efficient gas plants and/or reduce the number of hours gas plants supported by the CM can operate, reducing their contribution to UK emissions. Over time, as gas generators are needed less frequently, these assets may be removed from the market and isolated in a strategic reserve (see Section 6), funded by the government (DESNZ, 2024d). Within and alongside REMA, DESNZ (2024a) is also consulting on how the CM might be altered to better support gas generators' conversion to hydrogen-to-power or power with CCUS.

[11] Latent capacity refers to demand-side response and interconnectors—essentially power that exists within the system and can be called upon when needed but does not come directly from generators.

3. Short-duration energy storage

In systems with rapidly rising VRE penetration, electricity storage becomes more valuable for multiple reasons.

Recently, storage additions worldwide have been dominated by battery energy storage systems (BESS). BESS has become a key technology to shift power supply and demand to optimal times and reduce the role of fossil generation in the electricity system. Crucially, unlike thermal generators, BESS can also soak up excess VRE generation and discharge it when required, providing an opportunity for the economic utilisation of clean power that would otherwise be curtailed. Most BESS today is made up of lithium-ion batteries with 1–2-hour duration (Schmidt and Staffell, 2023).

3.1. The rise and roles of battery storage (BESS)

The UK has not deployed any technology-specific mechanisms for supporting storage, but BESS can technically participate in three main markets: ancillary services (of which participating in the system balancing mechanism is sometimes part), capacity markets, and arbitrage in the wholesale market, i.e. charging at times of low power prices, and discharging at times of higher prices.

BESS's role in ancillary services today is generally to provide frequency control services, as it can provide these more rapidly and cheaply than other generators. This enables fossil fuel generators to be retired with less risk to system stability. BESS can also play an important role in ensuring security of supply, both dynamically (it can be called on rapidly, protecting the system against the possibility of a sudden major plant or interconnector outage), and more generally in terms of additional potential generating capacity. These points justify the technology's inclusion in capacity markets.

BESS's biggest long-term contribution to system decarbonisation, however, is likely related to its function when profiting from arbitrage. When there are periods of surplus VRE, or when VRE would otherwise be curtailed due to transmission constraints, BESS can absorb this energy and transfer it to moments when demand outpaces VRE generation. As noted, BESS is likely to be particularly valuable in solar-dominated systems with much greater and more regular variability, as storage of only a few hours of duration could provide relatively secure supply, particularly to meet peak evening demand. It still plays a valuable role in wind-dominant systems, but the need for longer durations is likely greater to meet prolonged periods of low/no wind output.

In the UK and many European markets, VRE output is already rising to levels which create very low or negative wholesale prices, and/or lead to renewable output being curtailed behind transmission bottlenecks. BESS can increase the value of additional renewables in the electricity system and potentially enable fuller use of transmission capacity, neither of which can be provided by pure generating assets. There is thus a key reinforcing feedback dynamic between BESS and VRE deployment (Figure 2-5).

Combined with the potential for continued battery cost reductions, this self-strengthening feedback could be a powerful dynamic driving progress towards a power system that is carbon neutral, low-cost, and secure. The strength of these feedbacks will depend on many aspects of market design.

Notwithstanding this potentially powerful reinforcing dynamic, storage deployment may be subject to a self-limiting feedback insofar as it relies on revenues from wholesale market arbitrage. These arbitrage revenues rely on deep price spreads. However, over time, as BESS capacity increases, its absorptive arbitrage activity may reduce price spreads (which policymakers and the public may welcome), potentially cannibalising its revenues and weakening the case for further investment (see Figure 2-6).

In any technology transition, deployment of a new technology will inevitably slow as it approaches a saturation point. However, investment incentives associated with arbitrage revenues may be weakened before deployment is sufficient to enable a zero-carbon system. Relying on arbitrage incentives alone to drive investment may therefore be inadequate. This implies that establishing multiple revenue channels to reflect the different roles played by BESS (e.g. capacity, ancillary services) may be necessary to ensure ongoing investment.

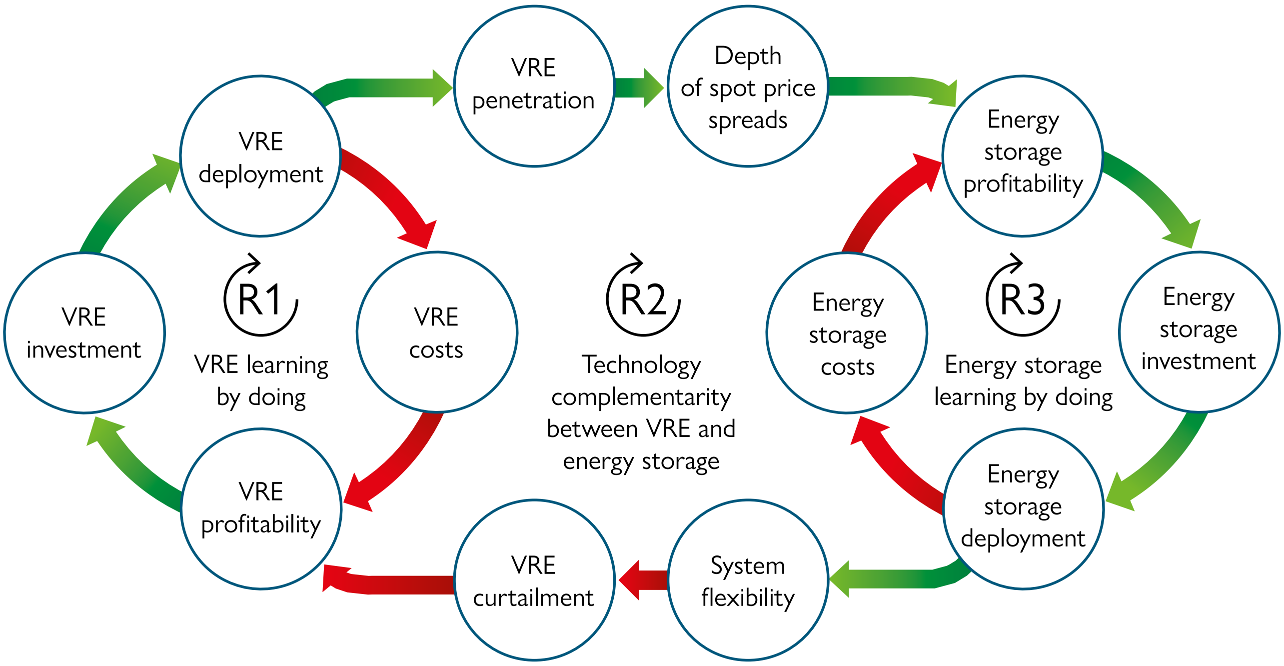


Figure 2-5: CLD of synergy effects between VRE deployment and storage deployment.
Note: Green arrows indicate a positive relationship (i.e. factors move in the same direction) and red arrows indicate a negative relationship (i.e. factors move in opposite directions). The letter "R" denotes a reinforcing feedback loop. Each feedback loop is accompanied by a brief explanation.

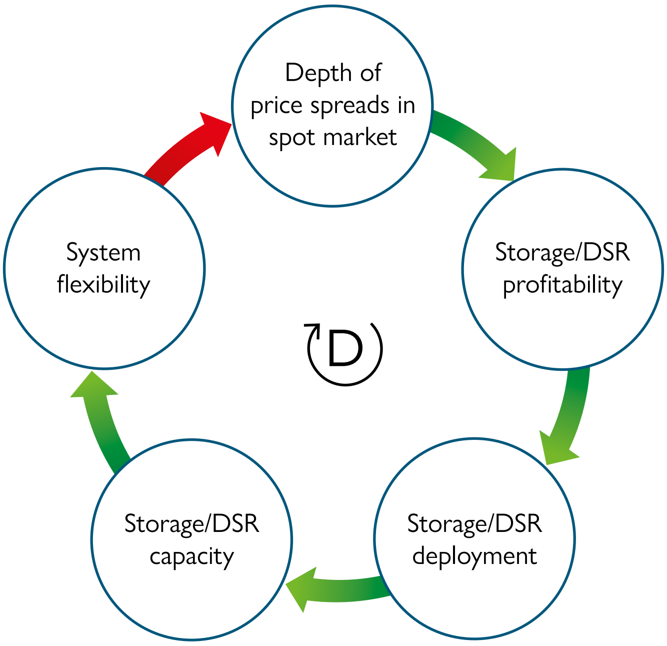


Figure 2-6: CLD showing dampening feedback on storage deployment.
Note: Green arrows indicate a positive relationship (i.e. factors move in the same direction) and red arrows indicate a negative relationship (i.e. factors move in opposite directions). White nodes represent variables in the system. The letter "D" denotes a dampening feedback loop.

3.2. China's energy storage mandate

Chinese provinces began implementing energy storage mandates in 2017. These policies required all developers of wind and solar capacity to deploy energy storage together with any new solar plants or wind farms.

In February 2025, the NDRC and NEA issued *Document 136*,[12] which called on local governments to remove their mandatory storage installation requirements from VRE project approval processes, effectively cancelling the storage mandate policy. Whether or not local governments follow through and annul their mandate policies remains to be seen. We retain our discussion of this policy here, as the dynamics we analyse are likely to remain relevant in the context of future storage policy development.

The specifics of storage mandate policies vary between provinces, as seen in Table 2-2. The ratio of energy storage capacity to VRE capacity is in the range of 10-20% in most regions, though the full range varies from 5% to 55%. The duration of storage required is generally in the range of 2-4 hours.

The energy storage mandate has led to the physical deployment of batteries on a large scale. However, a significant early challenge has been ensuring this equipment is actually used. The average utilisation rate[14] of storage capacity covered by this policy was just 9% in 2023[15]—far lower than the same figures for other storage models (e.g. standalone or user-side).

Table 2-2: Requirements for mandated energy storage co-installation with VRE projects.
Note: Data from ESCN.[13]

Provinces	ES deployment ratio (ratio of BESS capacity to VRE generation capacity)	Storage duration required (hours)
Tianjin	15%	
Hebei	15%-20%	2-4
Shanxi	50% (Generator-Grid-Load-Storage integration)	
Inner Mongolia	15%	4
Liaoning	10%	
Jilin	15%	2
Shanghai	20%	2
Jiangsu	10%	2
Zhejiang	10%	2
Anhui	5%	2
Fujian	10%	2
Shandong	20%	2
Henan	50% (Generator-Grid-Load-Storage integration)	2
Hubei	Wind 30%, Solar 25%	2
Guangdong	10%	2
Guangxi	Wind 20%, Solar 10%	2
Sichuan	15%	2
Guizhou	10%	
Yunnan	10%	
Xizang	20%	4
Gansu	10%-15%	2-4
Qinghai	15%	2
Ningxia	10%	2
Xinjiang	10%-20%	2

[12] NDRC and NEA (2025). Notice on deepening market-oriented reform of new energy on-grid prices and promoting the high-quality development of new energy. 发改价格[2025]136号
[13] See ESCN (2024). List of the latest policies in 31 provinces on new energy co-installation of storage in the era of prioritizing consumption.
[14] Utilisation rate (平均运行系数) is defined as the ratio of a facility's full-load hours in a given period to the length of the reporting period.
[15] See 2023 Electrochemical energy storage station industry statistics and data.

The core problem has been a lack of ways for energy storage to participate in markets and earn revenues. In provinces where spot markets are undeveloped or in early stages, and most output from renewables is sold through guaranteed purchase and the MLT market, there is relatively little opportunity for renewable operators to increase their revenues by using storage to vary the timing of their output. Grid operators generally rely on coal plants to provide security of supply and to support the stability of the grid, meaning BESS is not called on. Per NEA data, thermal power generators received 91.4% of all ancillary service market revenues in H1 2023, or C¥25.4 bn in absolute terms.[16] This contrasts with the UK and some (not all) EU countries, where BESS is utilised for its ancillary services. However, in the UK, the system operator (then National Grid) acknowledged that for some years its computer systems had, in practice, continued to prioritise natural gas before utilising BESS for system stability (Clark and Millard, 2024).

As a consequence, in China the energy storage mandate has initially had a mixed effect on the reinforcing feedback between deployment of renewables and deployment of storage. It has not strengthened this feedback as much as it could, because underutilisation of assets means that physical deployment is not necessarily translating into increased system balancing ability. At the same time, it has somewhat weakened this feedback by increasing the costs of renewables deployment (see Figure 2-7).

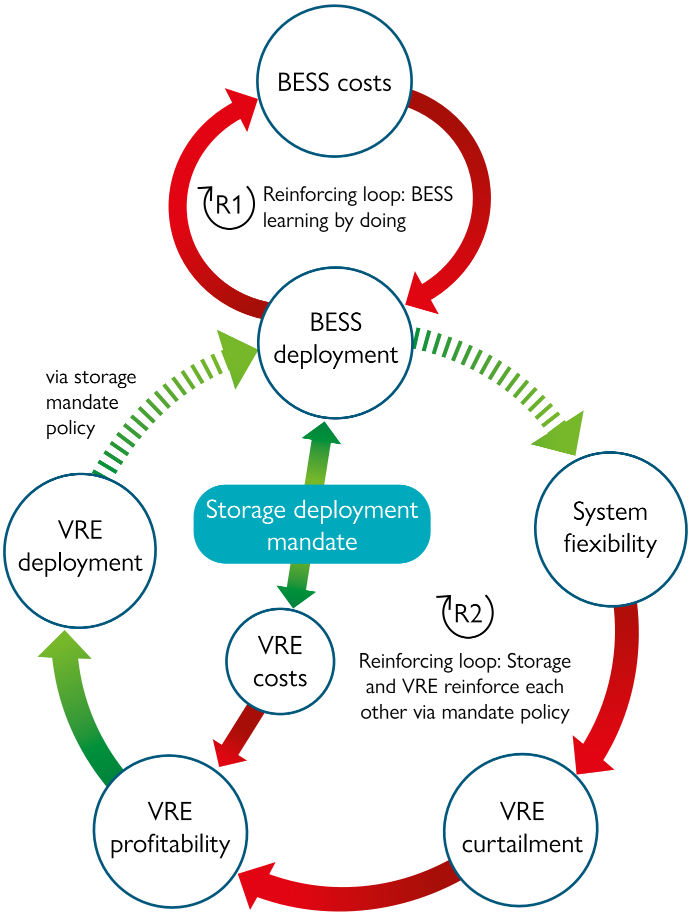


Figure 2-7: CLD showing the feedback loops associated with the energy storage mandate policy. Note that the causal link from "VRE deployment" to "BESS deployment" represents the effect of the mandate policy, and is dashed to indicate that this relationship would break if the mandate were abolished, which it now has been (in February 2025). The arrow between "BESS deployment" and "System flexibility" is dashed to indicate that this relationship only holds if installed BESS is actually utilised. Green arrows indicate a positive relationship (i.e. factors move in the same direction) and red arrows indicate a negative relationship (i.e. factors move in opposite directions). White nodes represent variables in the system. Blue rectangular nodes represent policy factors. The letter "R" denotes a reinforcing feedback loop.

[16] See NEA (2023). The scale of market-traded electricity grew steadily in H1.

3.2.1. Addressing the underutilisation problem

Many provinces are now taking action to address the problem of underutilisation of BESS assets. Capacity leasing rules have been introduced to allow new VRE generators to rent or purchase the energy storage capacity of independent BESS facilities instead of building their own. Various provinces and municipalities have introduced new policies in line with this design.

The leasing approach in principle has two advantages. Firstly, independent energy storage facilities will operate in response to system needs (insofar as they are able to participate in the market), unconstrained by the contract structures of individual renewable generators, which are likely to create different incentives. This should increase utilisation rates, ending the phenomenon of VRE developers installing low-cost, low-quality storage with no intention to use it, and instead making a more positive contribution to system balancing.

Switching from generator-side to independent business models also fundamentally transforms the role of BESS from smoothing output of one VRE facility to helping balance the grid. This set-up also brings a new revenue stream to independent BESS facilities (in the form of capacity leasing payments). Secondly, the independent storage facilities are likely to benefit from some economies of scale, reducing the initial investment and operation and maintenance costs, while leading to greater efficiencies in operating strategies.

The guiding prices for energy storage capacity leasing announced by provincial governments pursuing this approach range from ¥150-337/kWh/ year, with an average of ¥243/kWh/year, but the actual average price formed through the capacity leasing market is only around half that level, at ¥126/kWh/year.[17] The leasing approach requires agreements between renewable generators and independent storage operators on how costs and revenues will be shared, but early experience suggests this is not a significant barrier.

The advantages of the capacity leasing approach to the energy storage mandate—namely increased utilisation and lower costs—strengthen the policy's effect on the helpful reinforcing feedback loop shown in Figure 2-7.

Some provinces are addressing the underutilisation problem by asking VRE developers to hand over the operation of energy storage assets to the grid. As with the leasing approach, this allows the storage assets to be used when they are most needed by the system, instead of in response to the narrower interests of individual generators.

3.2.2. Considering the allocation of energy storage costs

Allocating the costs of energy storage to VRE investors, as the energy storage mandate does, saddles generators with extra costs for little benefit. Equipping a solar plant with energy storage (based on 20% capacity ratio, 2 hour storage) is estimated to increase initial investment cost by 8-10% (KPMG and CEC, 2023). For a wind power project equipped with energy storage of the same capacity, the investment cost could increase by 15-20%.

This may not be the best way to allocate the costs of energy storage if the overall goal is moving cost-effectively to a power system centred on low-carbon power and minimising system costs. The UK Energy Research Centre (2018) reviewed international evidence on the costs of energy storage and concluded that it would be inefficient to require all VRE generators to self-balance by providing their own storage. Instead, it advised that security of supply, as well as system stability—which are properties of the system—could be provided most cost-effectively at the system level. For similar reasons, in its REMA programme, the UK government has decided not to pursue the option of an equivalent firm power auction in which VRE would be required to compete against thermal power plants for contracts to supply firm (fully dispatchable) power (DESNZ, 2024e). This has been assessed as likely to result in overinvestment in flexibility and balancing services, increasing consumer electricity prices.

In China, the design of the energy storage mandate has been influenced by the legacy of past policies. In provinces where developers of new renewable power plants still have access to guaranteed purchase contracts, the profits available from these can be high. The cost of storage can be passed to these developers without substantially weakening the case for renewables investment. In future, as the role of guaranteed purchase contracts continues to decline, there may be advantages to reforming or replacing the mandate so that the costs of storage are borne by the whole system, instead of solely by renewable generators.

3.2.3. Increasing the opportunities for energy storage to participate in markets

Regulators have begun to address the market design features that limit BESS profitability and development. There are important opportunities to advance further in this direction.

[17] Data are from Energy Storage Application Branch of China Industrial Association of Power Sources (2024). 2024 White paper on development of shared energy storage in China.

First, power market design should provide arbitrage opportunities to fully leverage BESS flexibility. Advancing spot market development and loosening spot price floors and caps would be effective measures to this end (Figure 2-8). Data on energy storage utilisation rates is only available for 2023 at present, so it is not yet possible to assess the effect of recent spot market introductions (e.g. in Shandong and Gansu in 2024) on BESS utilisation. While allowing greater price variation by widening price limits in spot markets may strengthen dampening feedbacks related to wind and solar deployment in the short term by increasing price risk, the resultant deployment of BESS would serve to offset this effect by strengthening price signals and efficiently shifting power supply and demand.

Second, continued development of competitive ancillary service markets with fair access and participation criteria will benefit both BESS (by creating additional revenue streams), and the entire power system, by promoting lowest-cost service provision. Provinces are establishing different markets and revenue channels for BESS facilities, but progress remains uneven to date (see Table 2-3).

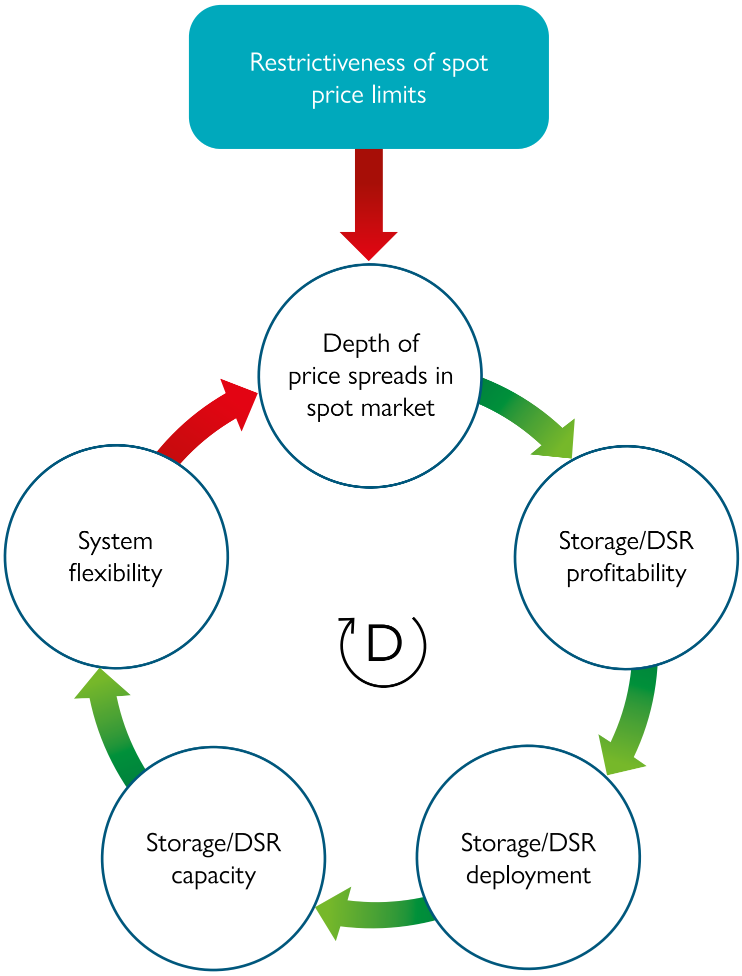


Figure 2-8: CLD of spot price and storage arbitrage interactions.
Note: Green arrows indicate a positive relationship (i.e. factors move in the same direction) and red arrows indicate a negative relationship (i.e. factors move in opposite directions). White nodes represent variables in the system. Blue rectangular nodes represent policy factors. The letter "D" denotes a dampening feedback loop.

Table 2-3: Revenue channels for standalone energy storage in selected provinces in 2023.[18]

Area	Capacity leasing	Spot market arbitrage	Ancillary services	Capacity compensation
Shandong	√	√	√ (Frequency modulation)	√
Shanxi	√	√	√ (Frequency modulation + standby)	
Hunan	√		√ (Peak shaving)	
Guangdong	√	√	√ (Frequency modulation)	
Guangxi	√		√ (Peak shaving)	
Gansu	√	√	√ (Frequency modulation)	
Ningxia	√		√ (Peak shaving)	
Qinghai	√	√	√ (Frequency modulation + Peak shaving)	√
Zhejiang	√		√ (Various)	√
Jiangsu	√		√ (Peak shaving)	
Henan	√		√ (Peak shaving)	
Hebei-Jinan	√			
Guizhou	√	√	√ (Peak shaving)	

Third, BESS revenues can be supported by capacity remuneration mechanisms. The NDRC has advocated capacity remuneration mechanisms for standalone BESS since 2021,[19] yet to date just five provinces had followed through as of November 2024.[20] The current capacity leasing mechanism associated with the wind and solar storage mandate provides some fixed, capacity-based revenues for BESS, but risks limiting renewables deployment by imposing additional costs on developers. For this reason, a capacity remuneration mechanism that treats storage flexibility as a system property, for example by transferring costs to users, may be preferable.

[18] China Electricity Council & Huaneng Tiancheng Leasing (2024), White Paper on New Energy and Energy Storage Participation in Power Market Transactions.
[19] NDRC and NEA (2021). Guiding opinions on accelerating and advancing new-type energy storage development. 发改能源规[2021]1051号
[20] These provinces are Shandong, Xinjiang, Inner Mongolia, Gansu, and Hebei. See Digital Energy Storage Network (2024). New-type energy storage stations are showing a scaling-up trend.

4. Long-duration energy storage

4.1. LDES in China

Long-duration energy storage (LDES) is widely expected to play an important role in the transition to clean power. It can contribute to balancing supply and demand over longer timescales, increase the power system's capacity to absorb large quantities of VRE generation, and help to ensure security of supply.

The definition of long-duration energy storage varies internationally. A U.S. Department of Energy report defined long-duration energy storage as having a continuous operation (discharge) time of at least 10 hours and a service life of 15 to 20 years (Denholm et al., 2021). In the UK, DESNZ (2024b) defines LDES as energy storage that can continuously discharge at maximum power for at least six hours. In China, the energy storage industry association has proposed a definition of LDES as technologies that can operate for at least four hours (with several subsidiary definitions for different durations).[21]

In China, the capacity of LDES needed in a fully decarbonised power sector has been estimated at over 700 GW (Miller-Wang *et al*., 2024). Given the potential for rapid growth in the frequency of VRE surplus events, as discussed in Chapter 1, LDES is likely to become valuable to the system for its absorptive capacity much earlier than it becomes necessary for its contribution to security of supply.

The deployment of LDES is likely to require substantial policy support, for several reasons. It has higher capital costs than short-duration energy storage and is likely to be used less frequently due to its (typically) slower response speed. Its probable infrequent use makes its revenues, and overall profitability, highly uncertain.

Pumped hydropower is the most mature form of LDES in China currently, and a capacity payment mechanism, similar to the coal power capacity payments described in Section 2.1, has been implemented to support existing and new-build plants.[22] The size of these payments, launched in 2023, is determined on a plant-by-plant basis by the NDRC. The mechanism is paid for by building its costs into transmission and distribution charges.[23] In the longer term, regulators may reduce these payments as spot and ancillary service markets mature,[24] which would provide pumped hydro with stable, market-oriented revenue channels.

Besides pumped hydro, pilot projects to demonstrate a variety of LDES technologies are underway across many of China's provinces. The technologies being tested include compressed air energy storage, liquid flow battery energy storage, flywheel energy storage, molten salt heat storage, and hydrogen energy storage. Policy support for LDES in China is perhaps most mature in Shandong, where dedicated support mechanisms were introduced in 2023.[25] The policy supports LDES pilots that meet certain eligibility criteria:

1. At least 100 MW capacity.
2. Capable of discharging at full power for at least four hours.
3. Round trip efficiency at least 60%.
4. Project lifespan at least 25 years.

Support mechanisms include grid connection priority, supporting spot market participation, dedicated capacity payments, and exemption from certain tariffs. The policy also provides for favourable conversion factors to encourage VRE developers to meet their storage mandate requirements by leasing LDES capacity (instead of short-duration BESS capacity), however the storage mandate policy is set to end in 2025, per *Document 136*.

Policies similar to those in the Shandong package could be transformative. If the capacity payment provides enough

[21] As reported by outlet Polaris Energy Storage Network.
[22] NDRC (2023). Notice on pumped hydropower station capacity pricing and related matters. 发改价格[2023]533号
[23] NDRC (2021). Opinions on further improving pumped hydropower price formation mechanisms. 发改价格[2021]633号
[24] Ibid.
[25] See Energy Administration of Shandong Province (2023). Several measures to support pilot applications of long-duration energy storage. 鲁能源科技[2023]115号

confidence in revenues to enable investment, participation in the spot market will allow the storage to operate in response to system needs and market incentives. Exemption from transmission and distribution tariffs, as well as government funds and surcharges when charging, can increase participation in arbitrage for storage and improve its profitability.

Early signs affirm the transformative potential of such LDES support policies. In the first two months of 2025, a total of 19 LDES projects were announced nationwide in China, totalling 5.487GW/17.688GWh. Shandong led the pack, by far, announcing seven projects totalling 3.01GW/10.404GWh (nearly 55% of the national total, by GW).[26]

At present, there is no national policy to support the deployment of LDES and ensure its commercial viability, apart from the capacity payments to pumped hydro. Replicating policies such as those being piloted in Shandong on a wider scale could be important for bringing more of the technologies currently being tested in demonstration projects into the market.

4.2. Revenue cap-and-floor policies: possible applications to LDES in the UK

As the UK moves towards a decarbonised power system, it has grown increasingly apparent that the electricity system does not have sufficient LDES to enable gas plants to exit the system.

There is currently only 2.8 GW of LDES capacity (nearly all in the form of 40+ year-old pumped storage hydro projects), while estimates suggest 11.5-15 GW will be needed by 2050 to achieve net zero (DESNZ, 2024c). High build costs and long deployment timelines for pumped storage have historically deterred new investment, but revenue uncertainty and volatility as the electricity system decarbonises have injected additional risk for newer forms of LDES (White, 2024).

When the UK government began consulting on how to best ensure sufficient LDES deployment, many respondents recommended a cap-and-floor design similar to that used for interconnectors (BEIS, 2022) (see Box 2-1 below). Interconnectors and storage share many similarities, both in their high up-front costs and uncertain revenue. Both technologies are critical enablers of a low-carbon power system, as they deliver high system value due to their ability to transport VRE power across geographies or time.

[26] See ESCN (2025). NEA has set the tone, 12 provinces and cities are emphasising building, and long-duration energy storage is entering the development fast lane in 2025.

BOX 2-1: Revenue cap-and-floor mechanism for interconnectors in the UK

Interconnection plays a vital role in securing the UK's electricity supply (Newbery and Grubb, 2015). In 2014, the UK had only 4 GW of interconnection to neighbouring countries, but this had grown to almost 12 GW by 2024, reducing the need for new UK generation capacity and keeping UK capacity market prices low.

This expansion of interconnectors was triggered by a reform introduced in 2014: a (revenue) cap-and-floor mechanism. Prior to the cap-and-floor scheme, private investors were expected to build transmission lines driven by the potential to profit from price differences between the two connected systems. However, investors were deterred by large uncertainties, and it became clear that reforms would be needed to expand the UK connections to anything near the level that models suggested would be optimal.

The solution developed was to legislate upper and lower limits for revenues from new interconnectors (Figure 2-9). The floor assured investors of minimal downside risk. Importantly, the cap-and-floor range ensured that interconnectors would have incentives to operate efficiently, according to real-time system needs.

This design proved highly effective, catalysing significant investment in interconnector capacity. Top-up payments to the floor would be funded via transmission charges paid by all electricity users, but these have never been required and instead, the regime has returned healthy profits (Ofgem, 2016).

Whilst the Chinese investment context is very different (with transmission investment led by State Grid), the cap-and-floor mechanism may be useful in the case of LDES to de-risk investment in the face of uncertainty in a changing system.

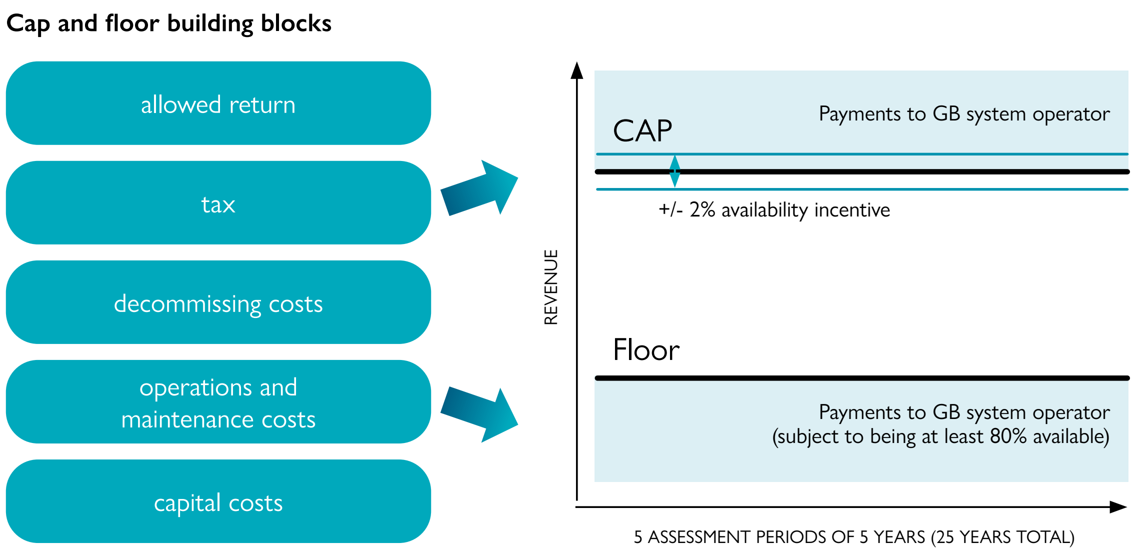


Figure 2-9: Design of interconnector cap-and-floor scheme.
Source: Ofgem, 2016.

The UK government is thus intending to develop a revenue-cap-and-floor policy for LDES, closely resembling the interconnector support regime (see Box 2-1), with some tweaks to reflect identified weaknesses in this scheme. Rather than using auctions to procure capacity (like for CfDs or the CM), the electricity regulator (the Office of Gas and Electricity Markets—Ofgem) will assess LDES projects using a range of criteria, including how quickly they can be deployed and their benefits to the whole energy system. The floor price will likely align with the minimum revenue needed to service projects' debt, as has happened in practice with interconnectors (DESNZ, 2024a).

While there will be two technology streams based on technology readiness level, both will support only those technologies that are advanced enough to be deployed today (DESNZ, 2024a). All technologies will be required to meet DESNZ's target duration of eight hours and will need to demonstrate that they would not be built without the support regime. BESS is not technically excluded, but such projects are unlikely to be chosen due to the additionality and duration requirements. Projects will be supported by the regime either until their first refurbishment or for 25 years of operation.

Having learned from the interconnector regime, Ofgem will also ensure it has greater flexibility to make amendments once the cap-and-floor is in place. While too much flexibility could undermine investor confidence, this is intended to help Ofgem reduce the risk of gaming by LDES operators. This flexibility is felt to be especially crucial in the context of recent price shocks, like those caused by Russia's invasion of Ukraine in 2022. One area where this flexibility has been criticised, however, is in the lack of a defined storage deployment target. The government does not wish to determine a certain amount of capacity to deploy through the cap-and-floor, which has raised questions about how well the scheme may work.

The fundamental risks of applying this design to LDES relate to the frequency of storage deployment and the degree of alignment with the decarbonising system's needs. A report by the House of Lords Science and Technology Committee (2024) felt that a six-hour duration requirement for LDES was too low (consequently raised to eight hours) and risked drawing away investment from longer-duration technologies. In practice, Ofgem's holistic selection criteria may negate these concerns, but revisions to the methodology or additional support mechanisms may be needed if longer-duration storage is required.

Additionally, while storage of an eight hour duration will likely have frequent cycling opportunities, it is not clear how often storage of longer durations might be needed. Unlike interconnectors, which are used daily, there is a greater risk that some LDES technologies will require floor payments. This could either undermine their likelihood of being selected by Ofgem or mean that the economic reality of the LDES cap-and-floor is quite different from the interconnector regime.

As the questions of duration highlight, there is also uncertainty relating to which technologies the regime will procure. Ofgem (2024b) will prioritise projects that can be delivered by 2030, suggesting the most developed technology stream will be dominated by pumped storage hydro, with at least 4.9 GW of capacity already in the development pipeline (Scottish Renewables, 2023). Scottish and Southern Energy has started works on the first new UK pumped hydro plant in forty years, on the promise of revenues cap-and-floor regulation.[27]

Some flow batteries, compressed air energy storage, sensible thermal, and liquified air projects may also receive support, but these technologies are not yet viewed as competitive, making it unclear how likely Ofgem will be to pick them (White, 2024). In the long term, the clear path to profitability through the cap-and-floor is likely to support the development of novel LDES technologies, but the strength of this feedback is as yet unknown.

[27] See SSE (2024). Pumped storage hydro critical to clean power.

5. Managing the declining role of coal power

The rapid growth of renewable power and energy storage described in earlier sections of this report imply a decreasing need for coal power.

This is reflected in thermal power plants' falling share of China's power generation: from 74% in 2015 to 63% in 2024.[28] The policy goals of achieving carbon peaking by 2030 and carbon neutrality by 2060 imply an eventual end to the use of coal power except where it is accompanied by carbon capture and storage.

At the same time, coal plants are currently relied on to provide security of supply, and as demand for electricity is rising, coal capacity continues to increase. Thermal power capacity, dominated by coal, rose from 1246 GW in 2020 to 1390 GW in 2023 (and 1440 GW in 2024)—an increase of 11.6% in three years (while renewable power capacity almost doubled in the same period). In 2024, nearly 95 GW of new coal capacity began construction, the highest level since 2015. This implies that a substantial number of new plants may come online in the next 2-3 years, further solidifying coal's role in the power system (Centre for Research on Energy and Clean Air and Global Energy Monitor, 2024).

An important challenge facing policymakers in this context is how to manage the declining role of coal power cost-effectively to maintain security of supply, while avoiding unnecessary investment in excess capacity. Launched in 2021, the national ETS has been set up as one of the main policies designed to reduce emissions from coal power in the future. We devote most of this section to considering how the effectiveness of the ETS could be improved, taking into account its interactions with other policies.[29]

5.1. China's ETS: a basic introduction

The scope of China's ETS is currently limited to the power sector. Other energy-intensive sectors such as iron and steel, cement, non-ferrous metals, chemicals, paper-making, and aviation are planned to be added in future, taking its coverage up to around 70% of current national emissions. China's ETS has special attributes that distinguish it from most other carbon pricing systems in the OECD countries.

First, there is no hard cap on emissions. The supply of emissions permits each year is a product of the benchmark emission intensity of coal plants and total electricity generation. The benchmark is set at around the emissions intensity of the 50th/60th percentile of the emissions intensities of plants within each of three plant size categories (large, medium and small coal plants). There is a separate benchmark for gas plants. The benchmark is changed in each commitment year by the government. Over the past five years, these decisions have cumulatively reduced the carbon intensity benchmark by around 11% for large coal plants (Table 2-4).

Table 2-4: Thermal power plant emissions intensity benchmarks under the Chinese national ETS, 2019-24.[30]

Units: tCO_2/MWh	2019-2020	2021	2022	2023	2024
Coal plants > 300MW	0.877	0.8218	0.8177	0.7861	0.7822
Coal plants ≤ 300MW	0.979	0.8773	0.8729	0.7984	0.7944
Coal gangue plant	1.146	0.9350	0.9303	0.8082	0.8042
Gas plant	0.392	0.3920	0.3901	0.3305	0.3288

[28] Per data from National Bureau of Statistics.

[29] For an extensive collection of research papers on emissions trading, including many articles on aspects of the Chinese ETS, see https://climatepolicyjournal.org/carbon-pricing/

[30] Data sources: MEE (2020). 2019-20 National emissions trading allowance quantity setting and allocation implementation plan (power sector). 国环规气候[2020]3号; MEE (2023). Notice on work related to 2021-22 national emissions trading allowance allocation. 国环规气候[2023]1号 ; MEE (2024). Notice on work related to 2023-24 national emissions trading allowance allocation and surrendering for the power sector. 国环规气候[2024]1号

Second, there is free allocation of emissions permits. Each plant is allocated permits based on its own output of electricity, multiplied by the benchmark carbon intensity.

Trading of permits then takes place between plants, driven by more efficient plants having more permits than they need and less efficient plants needing to acquire permits. It is only this trading that creates the carbon price.

The combined effect of the benchmark and free allocation is that coal plants with efficiency higher than the benchmark receive a net subsidy from the scheme, while those with efficiency lower than the benchmark make a net payment.

Even the less efficient plants only have to pay for the emissions that exceed their free allocation of permits, so the rest of their emissions are not subject to any carbon price.

Third, there is effectively a ceiling on the carbon price level. Per the *2023-24 national emissions trading power sector allowance quantity and allocation plan*,[31] the maximum quantity of permits that a plant is required to surrender at the end of the commitment period is limited to 120% of its free allowance, which means if a plant emits over 1.2 times its allowance, the additional allowance it should buy from market would not exceed 20%. This provision limits the costs of the policy for less efficient plants.

5.2. Dynamics of a typical ETS

An emissions trading scheme creates new dynamics in the relationships between technology costs, deployment, and emissions.

Figure 2-10 illustrates the core dynamics of a 'hard-cap' ETS in which there are no controls on permit prices (other than the penalties imposed for non-compliance).

The reinforcing feedback shown in Figure 2-10 is similar to those discussed in Chapter 1: deployment of clean power technologies leads to their reduction in cost, improving

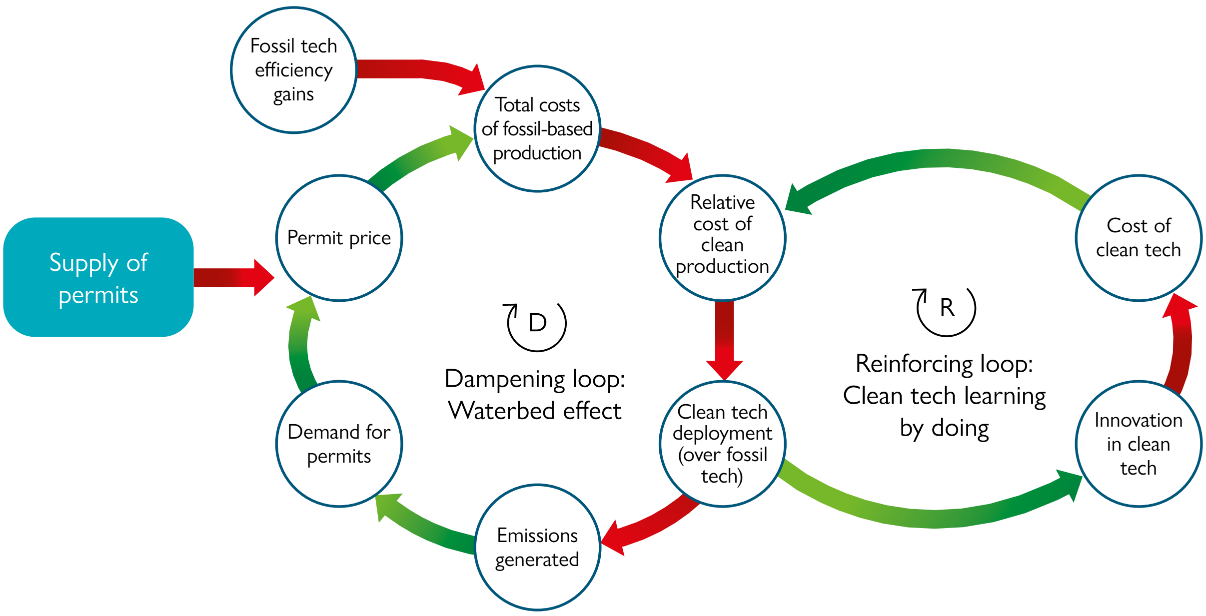


Figure 2-10: Interaction between feedback loops in a representative hard-cap ETS.
Note: The dampening loop on the left represents the waterbed effect, whereby emissions reductions among market actors depress permit prices and weaken incentives for further reductions. The reinforcing loop on the right represents a learning-by-doing effect of clean technology deployment. Green arrows indicate a positive relationship (i.e. factors move in the same direction) and red arrows indicate a negative relationship (i.e. factors move in opposite directions). White nodes represent variables in the system. Blue rectangular nodes represent policy factors. The letter "D" represents a dampening feedback loop, and the letter "R" represents a reinforcing feedback loop.

31 Attached to MEE (2024). Notice on work related to 2023-24 national emissions trading allowance allocation and surrendering for the power sector. 国环规气候[2024]1号

their cost-competitiveness relative to fossil fuels, and driving further deployment. This feedback is powerful in China, with solar and wind increasingly competitive in power generation. China accounted for the majority of global growth in investment in the energy transition in 2024, eclipsing the USA, EU, and UK (BloombergNEF, 2025).

The typical ETS[32] can contribute to strengthening this reinforcing feedback by increasing the cost of fossil fuel power relative to clean power, and provided there is a competitive market, this should drive further deployment of clean power technologies. However, the design of the ETS also creates a dampening feedback. Any increase in the deployment of clean technology leads to a decrease in demand for emissions permits, whose supply is fixed by the cap, and whose price therefore falls. The lower price reduces the incentive for further emissions reductions. This dampening effect (loop D1) is shown on the left-hand side of Figure 2-10. In this way, the typical ETS has a self-limiting effect. Any progress it makes will reduce its ability to contribute to driving further progress.

The politics of ETSs also often leads to oversupply of emissions permits, as policymakers are generally unwilling to impose severe costs on emitting industries, particularly when trade-offs with other policy objectives (e.g. industrialisation, export growth, employment) materialise.

Any decarbonisation progress achieved by other policies, such as subsidies or regulations that support the growth of renewables, or measures that decrease demand for coal power (like support for energy storage deployment and demand-side response), will tend to reduce the carbon price in the ETS, making the ETS less effective. The dampening feedback of the ETS means that any combination of the ETS and other decarbonisation policies is likely to achieve less than the sum of its parts. As a result, if an ETS is not carefully designed, it may impose administrative costs without making any significant positive contribution to the transition.

In the EU, this dynamic played out in the second and third stages of the EU ETS (from 2008 to 2012, and from 2013 to 2020) (Grubb, 2012; Koch et al., 2014), during which time the interaction between solar and wind subsidy policies and the ETS left little room for the ETS to drive decarbonisation; lower economic growth following the financial crisis and recession of 2008-9 again reduced demand and kept prices low. Carbon prices in the ETS were in the range of €20- €25/tCO_2 in 2005-2008, €10-€15/tCO_2 in 2009-2011, and €5- €10/tCO_2 in 2012-2018 (Tagliapietra and Demertzis, 2021). In response, the EU adopted the Market Stability Reserve in 2019, a mechanism with a similar effect to a carbon floor price, discussed in Section 5.5.

5.3. Dynamics of China's ETS

While the effects described above are common to many emissions trading schemes worldwide, the design features of China's ETS—using free allocations and an emissions benchmark instead of a hard cap—give rise to other dynamics specific to the Chinese system.

As noted above, the ETS generates a net subsidy to coal plants that are more efficient than the benchmark. By reducing the effective operating costs of these coal plants, this increases the relative cost of renewable power, weakening the reinforcing feedback shown in Figure 2-10. This runs counter to the objective of reducing coal's share of generation. Relatively efficient coal plants face no limits on their emissions and are incentivised to generate as much power as possible, running for longer periods to be allocated more permits, which they can sell to less efficient plants for profit.

Thus, the ETS's net subsidy to relatively efficient coal plants tends to increase their profitability, increasing the incentives for investment in more such plants. When new plants come onto the market and generate power, both the supply and demand for permits increase, creating both reinforcing and dampening feedbacks (Figure 2-11). Since relatively efficient coal plants are allocated more permits than they need, the net effect of their entering the market will be an increase in supply, which will tend to reduce the carbon price. While this dampening feedback moderates the incentive for constructing new efficient coal plants, this incentive remains higher than it would be if the ETS did not exist. This may increase the risk of unnecessary investment in excess coal power capacity.

[32] In fact there are a wide variety of ETS designs around the world – the latest World Bank State and Trends of Carbon Pricing (World Bank, 2024) identifies 36 ETS in operation, a growing number of these in developing countries, with some wide variations in designs.

China's ETS imposes a net cost on less efficient coal plants, as they have to buy additional allowances in the market to fulfil their commitments, as described above. But as in a typical ETS, this is subject to dampening feedbacks, which are depicted as loops D1, D3, and D4 in Figure 2-11. Any substitution of inefficient coal plants with more efficient coal plants or renewable power will tend to reduce demand for permits by more than it reduces supply of permits (since inefficient coal plants are allocated fewer permits than they need, see loops D1 and D3). The net reduction in demand will tend to lower the ETS price, decreasing the incentive for further substitution of inefficient coal plants. This tends to keep prices low and makes the ETS self-limiting. The prices observed in China's ETS have so far been very low, typically around ¥50-60/tCO_2 (7-8 Euro /tCO_2), and averaging ¥98/tCO_2 (13 Euro/tCO_2) in 2024 (Velev, 2025).

Progress in increasing energy efficiency of the coal plant fleet has been marginal in recent years: in 2022, Chinese coal power plants consumed coal an average rate of 300.7 g/kWh (with efficiency of about 41%), about 1% lower than in 2020.[33] This is already a high level of efficiency compared to the average for coal plants globally, for example, about 32-33% in USA in 2023 (Feng, 2023). More recently, due to soaring electricity demand requiring the increased operation of less efficient plants, the average coal consumption intensity increased slightly in 2023, up to 301.6 g/kWh across the coal power fleet. In response, the NDRC has encouraged the blending of biomass or ammonia in coal plants to reduce their carbon intensity.[34]

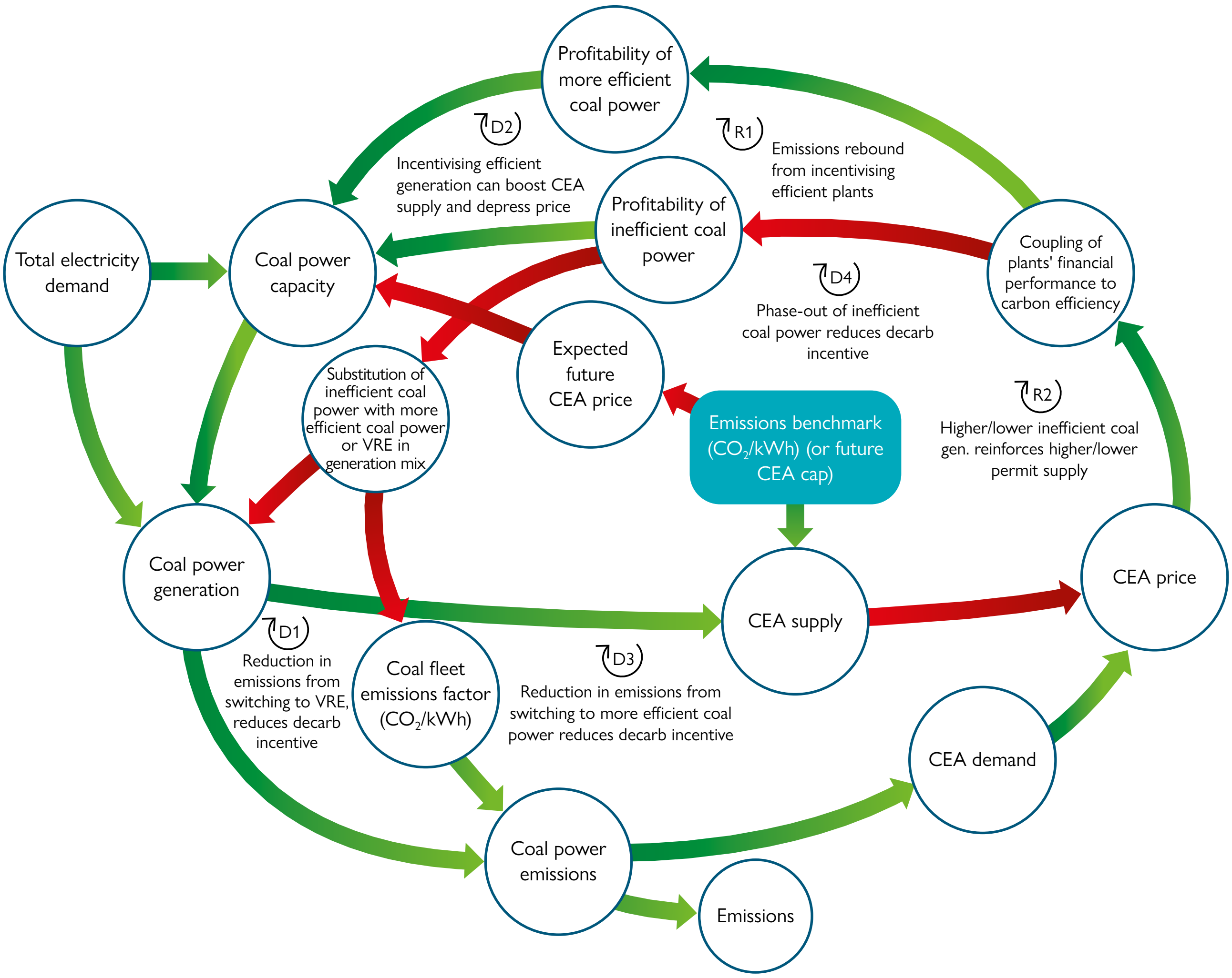


Figure 2-11: CLD showing feedback loops related to the Chinese ETS.
Note: Green arrows indicate a positive relationship (i.e. factors move in the same direction) and red arrows indicate a negative relationship (i.e. factors move in opposite directions). White nodes represent variables in the system. Blue rectangular nodes represent policy factors. The letters "D" and "R" denote dampening and reinforcing feedback loops, respectively. Each feedback loop is accompanied by a brief description.

[33] NBS (2024). China energy statistical yearbook 2023.
[34] NDRC and NEA (2024). Coal power low-carbon transition upgrading and building action plan (2024–27). 发改环资[2024]894号

5.4. Policy options for improving the Chinese ETS

Systematic reviews of academic research have found that carbon pricing has often led to emissions reductions (Döbbeling-Hildebrandt et al., 2024; Stechemesser et al., 2024), mainly through switching to lower carbon fossil fuels and efficiency gains. However, there is no evidence of carbon pricing schemes having triggered investments in zero emission technologies, and indeed some evidence suggests that they have not (Lilliestam, Patt and Bersalli, 2022). Within this scope of potential effectiveness, international experience suggests three reform options can improve the performance of an ETS. Here, we consider each of them from a Chinese perspective, with regard to their dynamic effects.

a) A hard cap on emissions, either limiting growth or forcing gradual decline.

A hard cap on emissions would disincentivise new coal power investment by limiting the space for any new coal plants to operate. This would break the unhelpful reinforcing dampening feedbacks shown in Figure 2-11 (loops D1, D3, D4), reducing the risk of unnecessary investment in excess capacity. The extent to which a hard cap would achieve this effect would depend on its stringency.

Many ETS systems, especially those in most of the Organisation for Economic Co-operation and Development (OECD) countries, have a hard cap on emissions, either declining linearly from a base year level, or allowing growth but at a restricted rate. The EU ETS takes 2005 as a baseline, and its trajectory implies emissions reductions of 61% by 2030 (Table 2-5). A key implication of intensity-based systems, like China's, is that they give little or no incentive to switch to non-coal generation, or to reduce the use of electricity from coal plants in other ways, since there is no carbon price pass-through to electricity prices.[35]

In China, a hard cap could, in principle, drive greater structural change. According to joint research by the International Energy Agency (IEA) and Tsinghua University, the ETS with its current design and tightening limits on carbon intensity could lower the emissions trajectory to 2035, but this would arise more from the use of carbon capture and storage (CCS) than from switching to renewables (International Energy Agency and Tsinghua University, 2022). In contrast, an ETS with a hard and stringent cap (and still with free allocation of permits) could accelerate the expansion of renewables, driving deeper emissions reductions.

However, a major difficulty is uncertainty. The government aims to peak emissions by 2030, and the introduction of an emissions-based "dual control" regime during the Fifteenth Five-Year Plan period (2026-30) could usher in the use of absolute emissions caps to this end. According to some studies, China may already have peaked its emissions in 2023-2024 (You, 2024), but this is not yet certain. Meanwhile, demand for electricity continues to grow rapidly. The ratio of the annual growth rate of electricity consumption to GDP growth has been over 1 since the year 2000, and stood at 1.34 in 2023. The drivers of future demand growth include growing electrification in road transportation and the residential sector, development of artificial intelligence, a rebound in consumption by energy-intensive manufacturing industries (such as petrochemicals, non-ferrous metals) driven by various factors, including lower power prices and hotter and longer summer days as a result of climate change (requiring more air conditioning).

Table 2-5: Example of hard cap in the EU ETS and one member state, Italy.

<table>
<tr><th rowspan="2"></th><th colspan="3">2020</th><th colspan="3">2030</th><th colspan="3">2035</th></tr>
<tr><th>Overall target (1990 baseline)</th><th>ETS target (2005 baseline)</th><th>Non-ETS target (2005 baseline)</th><th>Overall target (1990 baseline)</th><th>ETS target (2005 baseline)</th><th>Non-ETS target (2005 baseline)</th><th>Overall target (1990 baseline)</th><th>ETS target (2005 baseline)</th><th>Non-ETS target (2005 baseline)</th></tr>
<tr><td>EU</td><td rowspan="2">-20%</td><td rowspan="2">-21%</td><td>-10%</td><td rowspan="2">-55%</td><td rowspan="2">-61%</td><td>-40%</td><td rowspan="2">Not yet</td><td>-</td><td>-</td></tr>
<tr><td>MS: Italy</td><td>-13%</td><td>-43.7%</td><td>-</td><td>-</td></tr>
</table>

[35] For extensive analyses on the rationales and drawbacks of intensity-based ETS arrangements, see various papers in the carbon pricing collection of the journal Climate Policy.

Alongside the uncertainties around electricity demand, there are also deep uncertainties around how quickly energy storage and other flexible technologies can take the place of coal in providing security of supply. With all these uncertainties, a fixed cap with limited growth (for example, 1-2%) might be the outcome of a cautious approach to setting a trajectory for the 15th Five-year Plan period (2026-2030). A fixed cap would not break the core dampening feedback (shown in Figure 2-10) that makes the ETS self-limiting in its effect. The combination of a cautiously-set trajectory and this dampening feedback could result in continued low prices within the ETS, and a continuing risk of unnecessary capacity investment. Regardless of whether a hard cap is implemented, policymakers and industry still have a systematic incentive to overestimate emissions reduction to err on the side of oversupply in an ETS system. The subsequent paragraphs address how these oversupply tendencies can be mitigated.

b) Auction of emissions permits, instead of free allocation

Introducing an auction for emissions permits would weaken the link between the coupling of coal plants' financial performance to their efficiency and the profitability of more efficient coal plants (see Figure 2-11).[36] Used together with a hard cap on emissions permits (as described above), this could prevent relatively efficient coal plants receiving a net subsidy as a result of the ETS. Similar to the hard cap on emissions, auctions could weaken or break the unhelpful reinforcing feedback driving investment into relatively efficient coal plants (see Figure 2-11) but would not break the dampening feedback that makes the ETS self-limiting in its effect.

c) Carbon floor price

A carbon floor price weakens the relationship between demand for permits and the price of permits. This limits the range of the dampening feedbacks (loops D1, D3, D4 in Figure 2-11), making the ETS less self-limiting in its effect. Several different approaches to setting a floor price have been used by various countries (On Climate Change Policy, 2024). Some examples are given in Table 2-6.

Carbon price floors can be accompanied by carbon price ceilings, as used in the Australian and Californian systems to avoid excessive costs to firms (Grubb, 2012). They can be changed in response to changing economic conditions. The UK government introduced a carbon floor price in 2013 but implemented it as a "top-up tax" on the EU ETS. The Korean Ministry of Environment introduced a temporary minimum price on the secondary market in Korea's ETS in response to a continued decline in the carbon price (International Climate Action Partnership, 2021).

Table 2-6: Examples of carbon price floors worldwide.

Carbon floor price option	Examples	Notes
Auction reserve price for sale of allowances	California Quebec Washington State Germany New Zealand	Only works if auctions are introduced, to replace free allowances.
Top-up tax: a variable tax which increases the carbon price to the level of the price floor whenever the permit price is below that level	Netherlands Norway	More simple to implement that a market-stability reserve; more complex than a top-up tax.
Fixed tax in addition to the ETS carbon price (so that the total carbon price, the sum of the two, remains variable)	UK	Probably the simplest to implement. Can be made sector-specific, if the ETS covers more than one sector.
Sector-specific top-up tax	Netherlands	Having a different floor price in each sector or group of sectors (e.g. power vs industry) prevents dampening feedback operating between sectors.
Market stability reserve: permits are withdrawn or added to the market to keep supply within a specified range	EU	Effect is similar to a carbon price floor and ceiling, but is probably the most complex approach to implement.

[36] See also Yu, R., Zhang, D., & Zhang, X. (2024). Introducing auctioning in China's national carbon market: lessons from international and domestic practices. Climate Policy, 1–17. https://doi.org/10.1080/14693062.2024.2413856

As noted in Table 2-6, the different options involve different degrees of complexity in implementation. Auction reserve prices may be at risk of gaming, since market participants share an interest in tacitly colluding to lower prices (Tagliapietra and Demertzis, 2021). The EU chose possibly the most administratively complex approach, a market stability reserve (MSR), for reasons to do with its institutional structures.[37] The carbon price in the EU ETS rose significantly after the MSR came into operation (Figure 2-12), although other factors including a tightening of the emissions cap trajectory also played a role. The UK's fixed carbon tax is at the other end of the spectrum, perhaps the simplest of the available options (see Section 5.5).

China's ETS already has an effective carbon price ceiling, as mentioned above. A carbon price floor could be introduced as a complementary measure, to improve the effectiveness of the ETS in removing the least efficient coal plants from the system. This could be more feasible than setting a stringent hard cap with a declining trajectory, since it does not require confidence in the level of future electricity demand or the capacity of coal plants needed to ensure security of supply. The level of the floor price could be amended annually to respond to any over- or under-achievement.

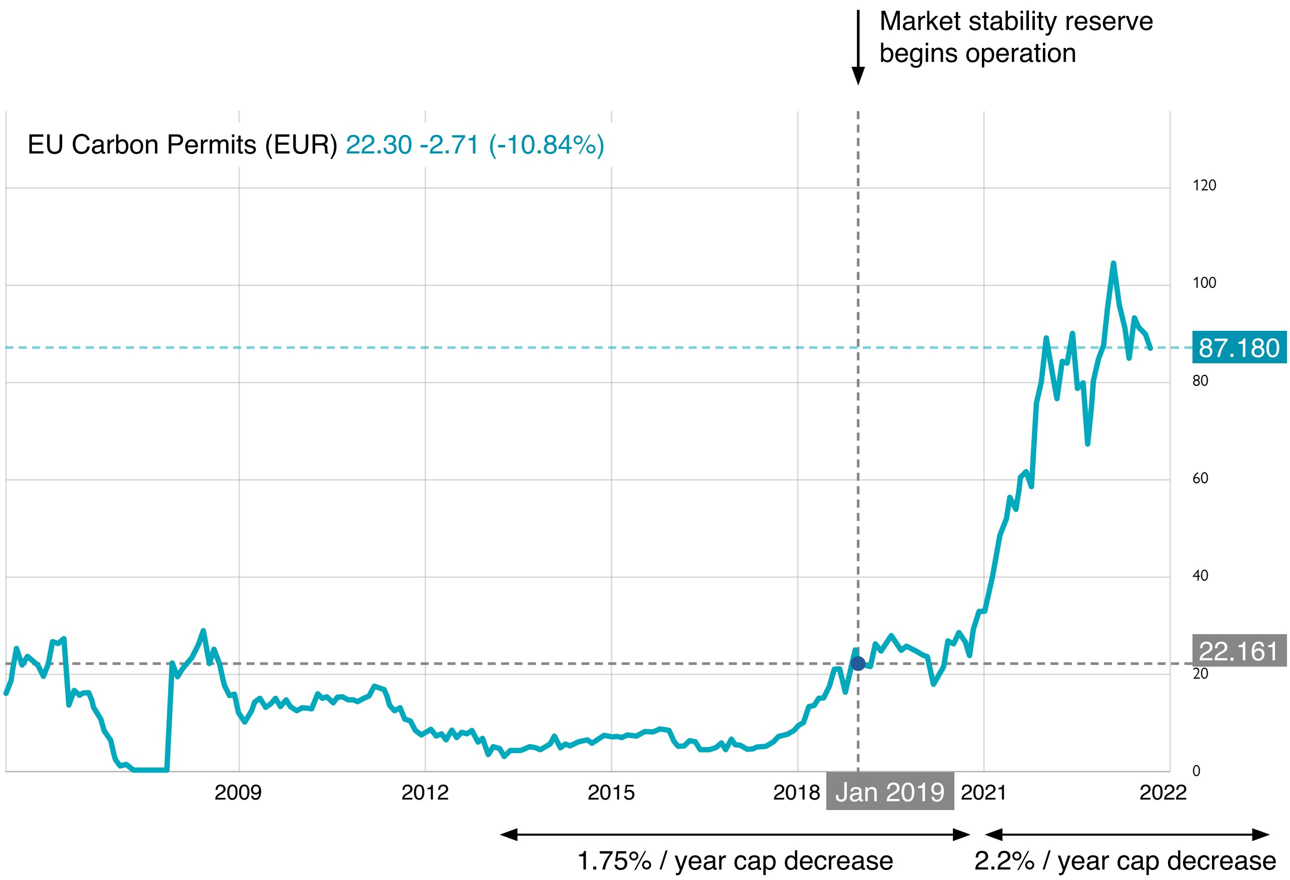


Figure 2-12: Carbon price in the EU ETS before and after the introduction of the market stability reserve. Source: Trading Economics. Annotations by authors.

[37] As a regulatory measure, the MSR could be agreed by a qualified majority vote of the Member States, whereas a tax would have required consensus (de Perthuis and Trotignon, 2014).

5.5. The UK experience: a hard cap, auctions, and a carbon floor price

The UK participated in the EU ETS from its establishment in 2005 until 2021 (when it withdrew as part of leaving the EU), but has since introduced its own ETS, largely modelled on the EU ETS. As noted above, the EU ETS has a hard cap on emissions.

Since 2013, auctions have been used as the default method for distributing allowances in the power sector. Carbon prices remained low throughout the ETS's first decade of operation, as indicated.

In 2013, the UK introduced a fixed carbon tax of £9/tCO_2 in the power sector, to be paid as an addition to the EU ETS carbon price. In April 2015, the level of this carbon tax was increased to £18/tCO_2. Between late 2015 and 2018, the combined effect of the EU ETS price and the additional carbon tax made coal power more expensive than gas power, reversing the order of coal and gas plants in the merit order (previously, coal power had been lower cost) (Figure 2-13).

This occurred in a context of rapid growth in renewable power, driven by feed-in tariffs and CfDs, and supported by a package of electricity market reforms including a capacity market and an emissions performance standard for thermal plants. In this context, the carbon tax contributed to many coal plants becoming unprofitable and being closed down. While the share of gas in the UK's power generation stayed roughly constant, coal power generation in the UK decreased by around 75% between 2012 and 2017, and its lost capacity was largely replaced through the growth of renewables (Sharpe and Lenton, 2021). This process of coal phase-down culminated with the closure of the UK's last coal power plant in September 2024.

The UK's experience shows how a carbon price can be highly effective when it alters the relative costs of competing technologies. It also shows how the effectiveness of a carbon price can depend on the context created by other policies.

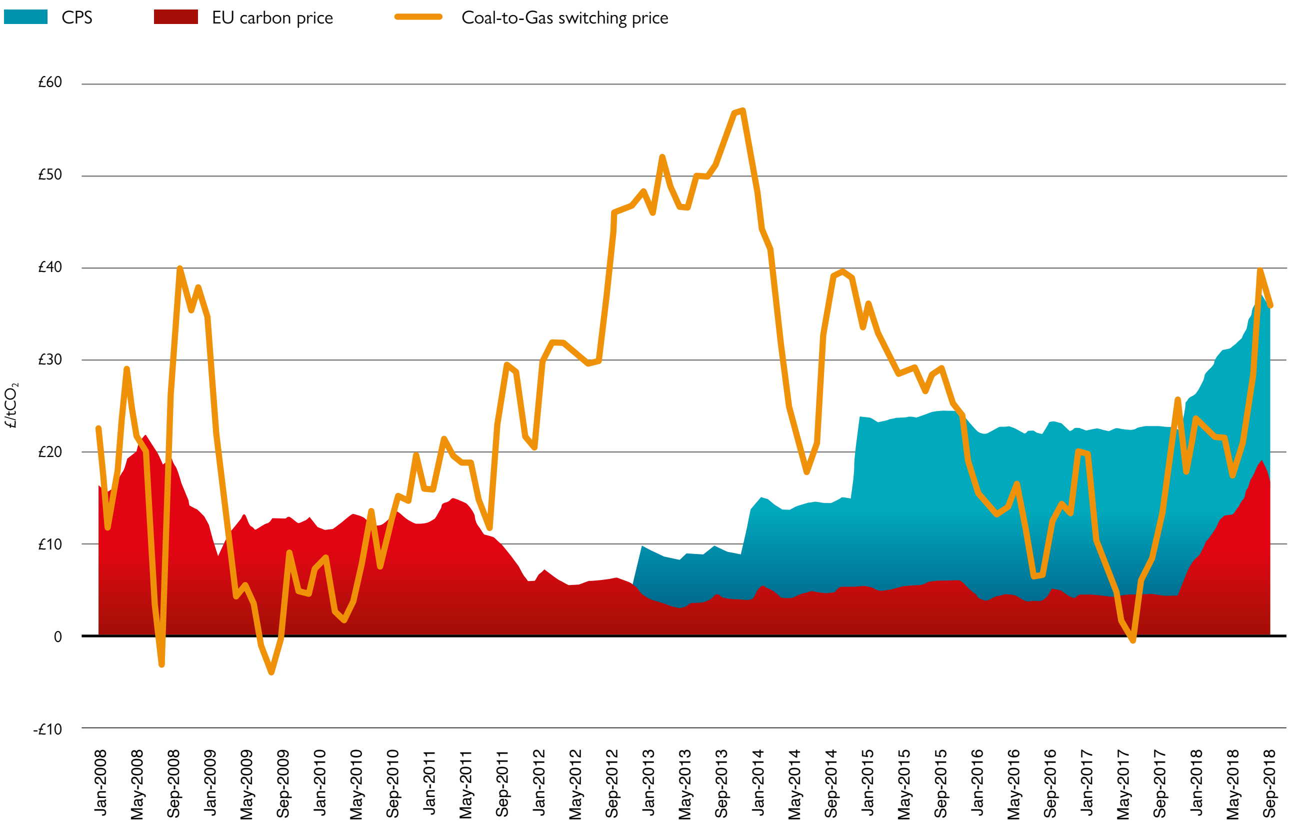


Figure 2-13: Evolution of the coal-to-gas switching price relative to the cumulative carbon price. Note: The carbon price support (a fixed tax—labelled CPS and coloured blue above) makes coal power more expensive than gas power in the UK. Data is from ICIS, Intercontinental Exchange and Bloomberg. Chart created by Philippe Guiblin.

5.6. A different role for carbon pricing in China

In addition to the limitations of China's ETS described in Sections 5.1 and 5.3, two other significant differences make it difficult for China to use carbon pricing in a similar way to the UK.

First, the UK's electricity demand was falling during most of the period in which its ETS has operated, whereas China's demand continues to rise. Second, and even more importantly, since gas plays a relatively insignificant role in China's power generation, any carbon price that effectively reduces coal generation will likely drive a transition to a mixture of VRE, hydropower, and energy storage, rather than a like-for-like replacement with gas. This transition is more complex than a coal-to-gas pathway, as the technical and economic attributes of coal and VRE are vastly different.

These differences minimise the ability of the ETS to be a strong driver of the transition to clean power in China. Instead, policies and market reforms that enable continuing investment in VRE and large-scale deployment of energy storage will likely be the primary drivers of the transition. In the power sector at least, the ETS is more likely a complementary instrument, preventing unnecessary investment in and utilisation of coal capacity, and removing coal plants from the system as they become surplus to requirements, starting with the least efficient. We believe the reforms discussed above—a hard cap, auctions for allowances, and a carbon price floor—could all help the ETS play this role more effectively in the power sector, and do not discount its potential usefulness in other sectors.

A final aspect to consider is the ETS's interactions with other policies.

5.7. Interactions between China's ETS and other policies

5.7.1. Interactions between the ETS and coal capacity payments

The capacity payments to coal plants, as discussed in Section 2.1, provide an additional source of revenue to all coal plants, regardless of their efficiency or the extent to which they are needed by the system. For relatively efficient coal plants, by increasing their profitability, this strengthens the reinforcing feedback that risks driving unnecessary investment in new plants (Figure 2-14).

For less efficient coal plants, the capacity payments offset the additional costs imposed by the ETS. Box 2-2 (below) compares the costs of the ETS for a coal plant of above average carbon intensity with the compensation that the same plant can receive from the capacity payments mechanism.

BOX 2-2: Comparison of financial flows generated by the coal capacity payment mechanism and ETS compliance for a representative coal power plant.

We take a coal-fired power plant with the following parameters as an example to show quantitatively the detrimental offsetting interaction between the coal capacity payment mechanism and the ETS:

1. Capacity: 300MW
2. Generation hours per year: 3500 hours
3. Carbon intensity: 0.85tCO_2/MWh (7% higher than the baseline, see Table 2-5 above)
4. Carbon price: ¥50/tCO_2.

Based on these parameters, the firm would have to pay about ¥2.9 million per year to buy additional CEAs (carbon emission allowances) from the market.

Under the coal power capacity payment mechanism, coal plants can get payment for their verified capacity, about 100 Yuan/kW in 2024-2025 (depending on the province—see Table 2-1. Assuming the verified ratio is 0.9, this firm can earn ¥27 million via capacity payments, much higher than the cost imposed by the ETS.

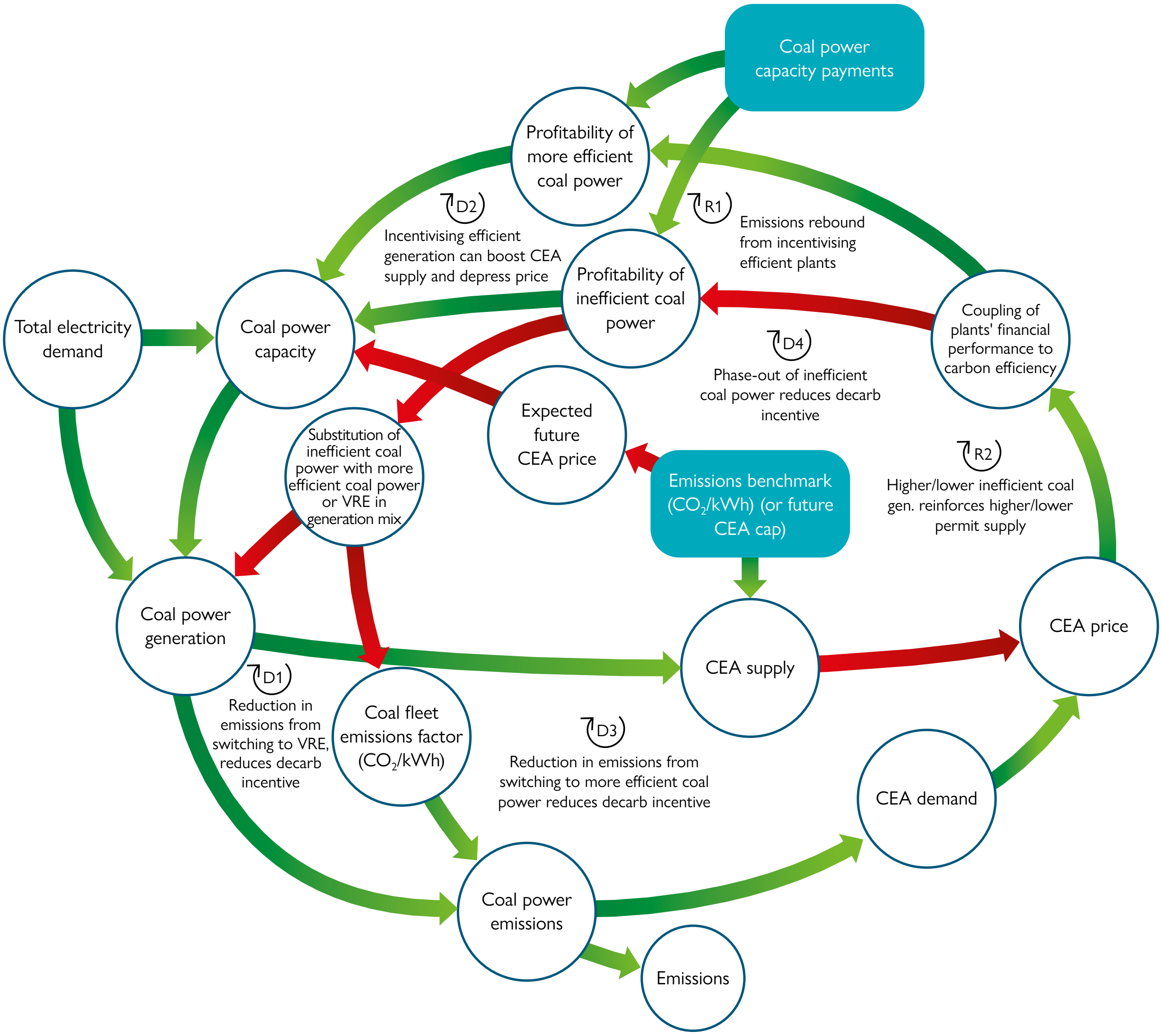


Figure 2-14: CLD showing effect of coal power capacity payments in the context of ETS dynamics.
Note: Capacity payments inflate profitability of both efficient and inefficient coal power plants, with complex secondary effects mediated by the six feedback loops depicted in the map. Green arrows indicate a positive relationship (i.e. factors move in the same direction) and red arrows indicate a negative relationship (i.e. factors move in opposite directions). White nodes represent variables in the system. Blue rectangular nodes represent policy factors. The letters "D" and "R" denote dampening and reinforcing feedback loops, respectively. Each feedback loop is accompanied by a brief description.

Of course, different policies target different objectives, and overlapping effects may, at times, be difficult to avoid. However, given the blunt nature of the coal capacity payment policy at present, this overlap represents a significant clash of policy objectives with the ETS. That is—the current design of the coal capacity payments will make it difficult for the ETS to achieve its desired effect of forcing inefficient coal power out of the market.

Adjustments to these policies could reduce the degree to which they clash, increasing the chances that they will achieve their objectives. One approach to resolving these policies would be the reforms discussed in Section 2: introducing competition between coal plants for capacity payments within the framework of a capacity market. This could limit the scope of the payments to the total capacity considered necessary for security of supply, and leave the least efficient plants to be subject to the carbon price without any offsetting compensation. With a high enough carbon price floor, this could gradually remove inefficient coal plants from operation when they become unneeded by the system.

5.7.2. Interactions between the ETS and the China Certified Emission Reduction program

A second policy interaction of interest is that between the ETS and the China Certified Emission Reduction (CCER) programme. The CCER scheme, re-started at the beginning of 2024, is a voluntary emissions reduction market, functioning in a way similar to the Clean Development Mechanism run by the United Nations Framework Convention on Climate Change (UNFCCC). CCER credits can be sold by developers of offshore wind, solar-thermal power, and afforestation projects. Companies participating in the ETS can buy CCERs instead of CEAs as a contribution to meeting their obligations under the ETS, but only to cover a maximum of 5% of their total CEA commitment. The aim of this policy is to support the development of less mature clean technologies. MEE has deliberately chosen only a few technologies for eligibility, although eligibility is expected to be expanded. More detailed guidance on the implementation of this policy exists at the provincial level. The price of CCER credits is close to the ETS permit price.

The CCER program creates a dampening feedback similar to that described above for a typical ETS. If it succeeds in incentivising the deployment of offshore wind and solar thermal power, the supply of credits will increase, and the carbon price (CEA price) will fall, reducing the incentives for further such deployment (Figure 2-15).

The link between the CCER and the ETS brings both policies into the same dampening feedback loop, with progress achieved by either policy reducing the effectiveness of the other. The 5% limit rule mentioned above restricts this offsetting effect in one direction: the availability of CCER credits cannot have a large effect on the ETS price. However, there is no limit to the offsetting effect in the other direction: if the ETS price is very low, it is likely to bring the CCER credit price down to an equally low level. This could prevent the CCER from achieving its desired effect of supporting the deployment of less mature renewable technologies. A floor price in the ETS, as discussed above, could prevent this offsetting effect.

If the scope of eligibility to sell CCER credits is expanded, it will be important to ensure the integrity of these credits and the additionality of the actions they support.[38] This is a general concern in voluntary carbon markets globally (Sylvera, 2025). Companies participating in these markets are increasingly navigating a trade-off between price and quality. Those looking for high-quality credits show willingness to pay more for projects that achieve durable carbon dioxide removal, and those involving afforestation, reforestation and revegetation, improved forest management, and sustainable agriculture). In China's CCER program, limiting the scope of eligibility to high-quality projects is one way to safeguard its effectiveness.

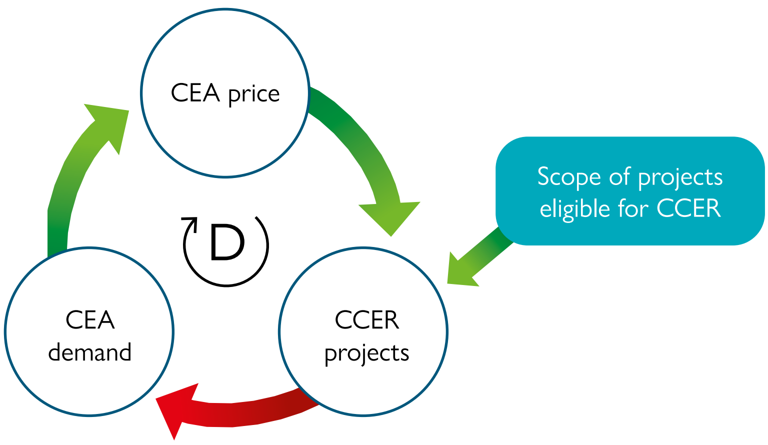


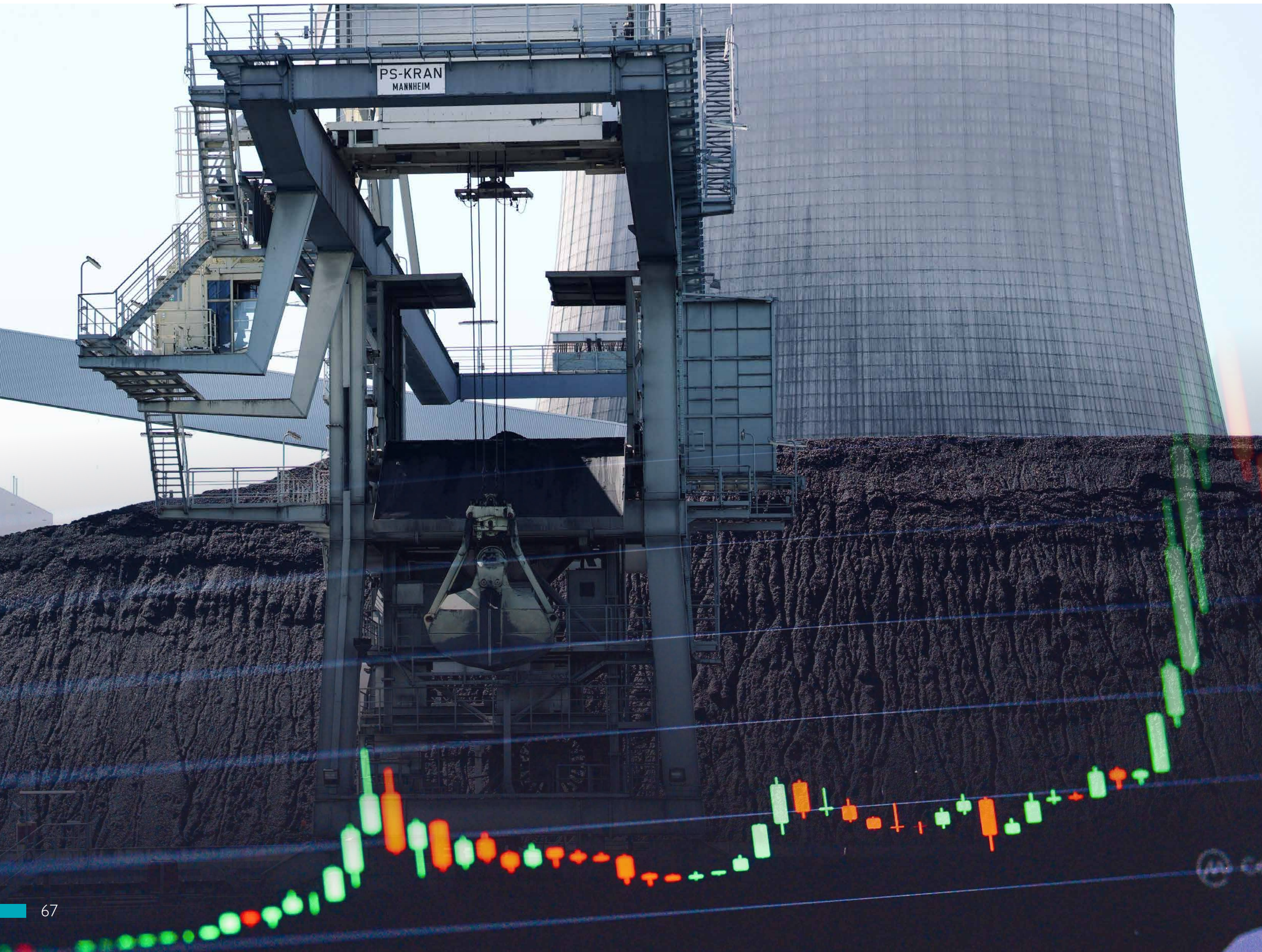
Figure 2-15: Dampening feedback of CCER scheme.
Note: This feedback prevents the carbon price (CEA price) rising too high. This effect will only strengthen as new methodologies are approved for CCER, widening the scope of eligible projects. Green arrows indicate a positive relationship (i.e. factors move in the same direction) and red arrows indicate a negative relationship (i.e. factors move in opposite directions). White nodes represent variables in the system. Blue rectangular nodes represent policy factors. The letter "D" denotes a dampening feedback loop.

[38] See MEE (2023). Letter on publicly soliciting suggestions for voluntary greenhouse gas emissions reduction project methodologies. 环办便函[2023]95号

5.7.3. Interactions between the power sector and other sectors within the ETS

While the scope of the ETS nationally and in most provinces is limited to the power sector, ETS pilots in a few regions extend to other sectors. Some provincial ETS pilots cover scope 2 emissions (those associated with purchased electricity, heat or cooling) for non-power sector entities. This arrangement reflects the fact that carbon prices on thermal power plants' scope 1 emissions are not easily passed through to electricity users due to the rigid pricing rules of China's power market. Some provincial pilots, such as Beijing's, also allow participants to purchase renewable power via green power trading (with bundled GECs) to offset their scope 2 emissions. This mechanism risks weakening provincial ETS decarbonisation incentives given the low prices of GECs (compared to carbon prices) and the absence of any caps on offsetting in this way. The inclusion of scope 2 emissions and GECs increase the complexity of provincial ETS pilots compared to the EU model. Scope 2 emissions will, however, be excluded from the national ETS when it expands to other non-power sectors, avoiding these policy conflicts.

When the national ETS is expanded to cover a range of industrial sectors, as planned, there is a risk that the core dampening feedback of the ETS will begin to operate across sectors. For example, progress achieved in decarbonisation of the power sector could reduce demand for permits, reducing the permit price, and decreasing the incentive for decarbonisation in other sectors such as steel or cement. One way to prevent this would be to have sector-specific carbon floor prices, as in the Dutch example cited above in Table 2-6. In each sector, these floor prices could be set at levels sufficient to alter the relative costs of competing technologies, as in the example of the UK carbon floor price in the power sector. An alternative option for constraining the self-limiting effect of the dampening feedback would be to restrict trading of ETS permits between sectors.



6. Strategic reserve

A strategic reserve refers to the practice of keeping some generation capacity on standby, outside the electricity market, to be called on only during system stress events.

The system operator can decide on the quantity of reserve capacity to procure, and payments are arranged, via auctions in many cases, to cover reserve generators' costs. Several European states, including Germany, Poland, and Belgium, have adopted strategic reserve policies with varying design characteristics, the main purpose being to get old, dirty but cheap coal plants (often using lignite or other low-grade coal) out of market operation. Strategic reserves are generally seen as an alternative to capacity markets, though in theory they could be complementary. Key differences between the two approaches are highlighted in Table 2-7.

Table 2-7: Comparison of strategic reserve and capacity market policies.

	Strategic Reserve (payments to capacity not normally operating in market)	Capacity Market (payments to capacity free to operate in the market)
Functional positioning	As a backup mechanism, it comes into play when market operations fail to ensure sufficient generation; deals with system stress events, and safeguards the security of power supply.	Through contractual agreements on reliable sources of capacity, it ensures timely response during system stress situations and maintains the security of power supply.
Operation mode	Contracts for a certain amount of capacity are signed in advance. These capacities do not participate in normal market operations and will only be put into use when called upon by System Operator, to tackle system stress events because the wholesale market provides inadequate capacity.	Capacity is contracted in advance through auction. Generators, energy storage providers or demand-side response suppliers can receive contracts if they are considered eligible (based on their ability to respond when there is system pressure). These plants can also participate in normal market operations.
Advantages	The support is targeted, to a limited amount of capacity (usually, generators that would otherwise close), and does not affect economics of the wholesale market, thus offering full value to new entrants in the market. Administratively quite simple.	As a general payment to all generators able to support security, in theory it offers maximum efficiency and avoids political choices about which generators to support – it is a generalised payment for security.
Disadvantages	Need for government to choose which plants to support, and negotiate payments. Bigger role for system operator in choosing when to activate. Could have gaming challenges (generators threatening to close completely when in-market economics deteriorate, in hope of getting paid to enter strategic reserve).	Amounts to a generalised subsidy to all relevant capacity, which can be taken as a windfall profit by incumbents. Exaggerated capacity needs would be far more expensive than for a SR. Payments available could help some new entry, but the implicit subsidy to all existing fossil fuel plants may be particularly problematic for systems trying to decarbonise. Need for sophisticated auctions, derating factors to reflect statistical availability, and delivery mechanisms, implies complex administration.

A strategic reserve could have advantages in the Chinese context relative to other capacity remuneration mechanisms. A key feature of the Chinese context is the dominance of coal and the continued construction of coal plants given rising electricity demand (with substantial uncertainty around future demand needs). This creates tension with the need to peak electricity emissions before 2030 and decline thereafter; older coal plants are at risk of retirement due to declining load factors, whilst new coal plants may risk becoming stranded, or at least underutilised. Strategic reserves typically target capacity that would otherwise be retired. Given the concern around plant retirement in China, this policy could smooth the economic and social impacts of plant retirements by enabling a shift to a reserve role, rather than subsidising generators with capacity payments to stay in the market.

However, there are also potential drawbacks associated with strategic reserves. First, by activating standby capacity in times of system stress, strategic reserves can effectively limit the revenues available to generators in the electricity market by preventing major price spikes. From an efficiency perspective, this could weaken scarcity pricing incentives that would otherwise drive investment in new generation capacity over time; and a lack of major price spreads could reduce incentives for the deployment of energy storage. On the other hand, however, the ability to cap extreme wholesale price spikes can be seen as a policy and political advantage (wholesale price spikes, however short, tend to attract unwelcome headlines, and it is hard to be sure how frequent or high they may be). Second, unlike capacity markets that support low-carbon technologies, strategic reserves generally exclusively target thermal generation. As such, there is a risk of industry lobbying or political biases leading to over-procurement of thermal capacity in reserve. Coal plants could be subsidised to stay in reserve, even past the point when they are genuinely no longer needed, driving up system costs. Transparent governance and auctions would be necessary to prevent this occurring.

Whilst much literature frames capacity mechanisms and strategic reserves as alternatives to each other, in principle they could exist together. Particularly in the context of uncertain demand growth, this could enable a capacity market with less ambitious (and hence much less costly) capacity targets, whilst retired thermal plants are kept available in a strategic reserve to protect the system against an unexpected surge in demand growth, or unusually long periods of low renewables output. There is always, however, some trade-off in terms of the incentive for new entrants, which could benefit from extended extreme prices if there is no strategic reserve.

Recent policy movements suggest that a strategic reserve may be a preferred solution in the Chinese context. In January 2024, the NEA called for retired coal-fired units to be held as emergency backup sources so as to enhance system stability.[39] In September of the same year, Guangdong authorities issued introduced capacity payments for emergency standby coal-fired power units, temporarily set at ¥260/kW/year. This figure is understandably higher than the standard coal power capacity payments (set at ¥100/kW/year in Guangdong, see Table 2-1), as standby units do not earn revenues through regular generation. Interestingly, it is substantially lower than the ¥330/kW/year figure quoted as the standard fixed costs of an operating thermal plant.[40] The cost of these payments is charged to commercial and industrial users as system operation costs.

[39] NEA (2024). Guiding opinions on energy work in 2024. 国能发规划[2024]22号
[40] NDRC and NEA (2023). Notice on establishing a coal power capacity price mechanism. 发改价格[2023]1501号

7. Conclusions and recommendations

This chapter has highlighted the need for new approaches to ensure security of supply in the context of VRE growth, as well as to avoid unnecessary investment in thermal power as its role in the system diminishes.

Having reviewed China's existing policies and the UK's capacity market, we have identified opportunities to expand the roles of short-term energy storage, long-term energy storage, and interregional transmission in increasing system flexibility and ensuring security of supply, while reducing reliance on thermal power. We have also identified measures that could increase the effectiveness of the ETS in preventing unnecessary investment and removing the least efficient coal plants from the system. Our analysis suggests the following policy priorities:

1. **Transition from capacity payments to a capacity market.** This could support the deployment of new flexible technologies, reduce the costs of ensuring security of supply, and avoid unnecessarily prolonging the operation of inefficient coal plants. (As described in Section 5.7.1, even for less efficient coal-fired power plants, the capacity payments more than offset the additional costs imposed by the ETS)

2. **Promote the deployment of BESS by enabling its greater participation in markets.** The energy storage mandate proved to be an inefficient policy, and following the release of Document 136, will now be abolished. A growing contribution of BESS to system flexibility can be supported by enabling its participation in spot markets and ancillary service markets, and capacity payment mechanisms (including either fixed payments or market-based schemes).

3. **Establish policies to support the deployment of new technologies for LDES to complement the growing pumped hydro storage capacity.** A revenue cap-and-floor policy could be one way to achieve this, by providing enough confidence in returns to incentivise investment. Measures such as those being piloted in Shandong, including grid connection priority, capacity payments, spot market participation, and exemption from tariffs, could also have positive effects.

4. **Strengthen the effectiveness of the emissions trading system, with the introduction of a fixed cap on emissions, auctions for permits, and a carbon floor price.** Given the uncertainty over future electricity demand, which inhibits the setting of a stringent cap, a robust floor price may be the most important of these options. This could also prevent the ETS from undermining the CCER in its objective of supporting the deployment of less mature low-carbon technologies.

5. **Consider establishing a strategic reserve, potentially alongside a capacity market, retaining the option to use coal-fired power plants that would otherwise be retired.** This could give provincial governments increased confidence in security of supply, reducing the risk of overinvestment in thermal power capacity, and allowing a strengthened ETS to remove the least efficient plants from the system. By taking back-up plants out of the market, it could also create more space for the operation of flexibility technologies such as energy storage, encouraging investment in their deployment.

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Chapter 3
Systems mapping and the Chinese power sector

Authors: **Peter Barbrook-Johnson, Max Collett, Simon Sharpe**

Contents

1. Introduction

The previous chapters of this report focussed on describing some of the key trends in the Chinese power sector, illustrating certain dynamics using the systems mapping and feedback loop research we have conducted.

This chapter flips our focus to ground the analysis in a comprehensive systems map (see Figure 3-1), developed over months of iterative collaboration with Chinese and UK experts, plus a participatory workshop in Beijing. We take this map as a starting point and conduct a deeper exploratory analysis of it to address several key questions relevant to China's power sector transition.

This approach provides a more comprehensive set of analyses and further questions. It shows different ways of interrogating a system map built with input from a range of stakeholders. As well as simpler feedback loops, the chapter illustrates paths or causal chains of influence into and away from key factors of interest (e.g. policies or outcomes), paths of influence between policy and outcomes, and more complex interacting sets of feedback loops. This combines elements of causal loop diagrams (CLDs) and participatory systems maps (PSMs), as described in Barbrook-Johnson & Penn (2022).

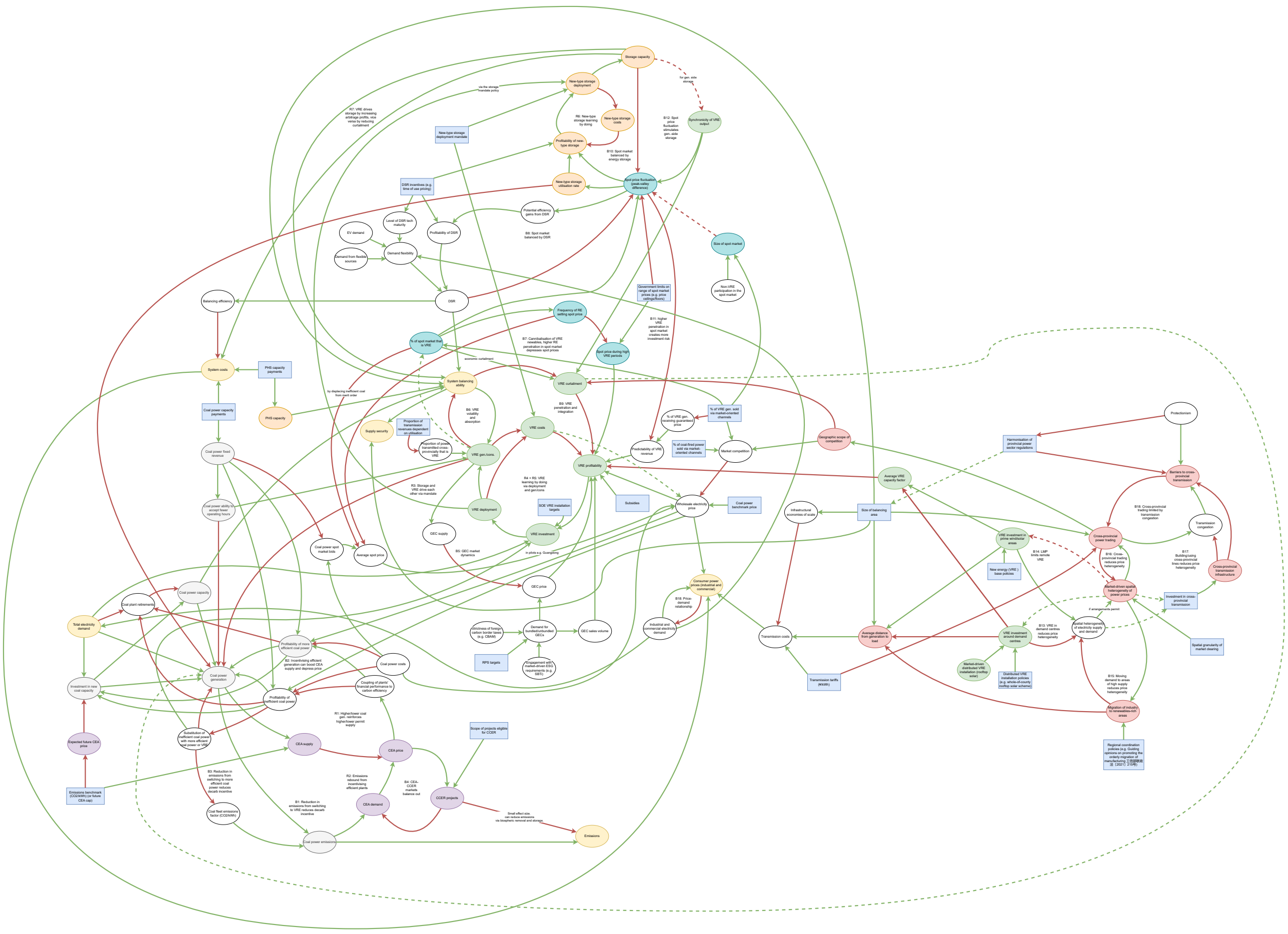


Figure 3-1: Overall systems map of the Chinese power sector.
Note: This smaller version is presented here to show the level of detail and complexity modelled. A larger, higher-resolution version is presented in Appendix B. The map was developed over months of iterative collaboration with EEIST researchers from China and the UK, plus a participatory workshop in Beijing with external Chinese experts. Green arrows indicate a positive relationship (i.e. factors move in the same direction) and red arrows indicate a negative relationship (i.e. factors move in opposite directions). White nodes represent variables in the system. Blue rectangular nodes represent policy factors. Other colour nodes represent thematic clusters of variables. Dashed arrows represent weak or conditional connections.

The chapter comprises four sections which emerged from this more exploratory analysis and the questions which arose in discussions with Chinese policymakers and researchers:

- Section 2: The interaction of current policy and market liberalisation with the three legs of the energy trilemma—costs, emissions, and security of supply—using a variety of subsections of our full map.
- Section 3: Policy consistency—that is, whether a range of current policies work together or undermine each other. Competing outcomes and trade-offs are sometimes unavoidable, but the analysis clarifies these and considers whether observed trade-offs are avoidable or could be minimised. We also consider what drives the key outcomes of profitability for coal power and VRE.
- Section 4: Large feedback loops around learning-by-doing, VRE cannibalisation, and technology change.
- Section 5: The role of price signals in the key feedback loops presented throughout this report. This can inform understanding of the potential impacts of market liberalisation , and can be used to identify potential interventions to strengthen or weaken related feedback loops in line with policy objectives.

2. Policy impacts on the energy trilemma: feedback loops and direct paths

Key energy policy objectives comprise keeping power prices low, reducing emissions, and maintaining security of supply (typically framed as "the energy trilemma").

Using this framing, this section focuses on how the trilemma objectives are affected by five policies: (i) coal capacity payments, (ii) the energy storage mandate (iii) market liberalisation, (iv) investment in cross-provincial transmission infrastructure and (v) the emissions trading system.

For each of these five policies, we divide our analysis into two stages. First, we consider how the policy impacts the trilemma objectives via some of the powerful feedback loops in the map. To illustrate these causal relationships, we develop simplified system submaps which only show the feedback loops that appear in causal chains between the policies and the outcome variable of interest. If there are no feedback loops between the policy and the trilemma variable, this analysis returns nothing.

Second, to complement with the feedback loop analysis, we also look at direct causal paths between policies and the trilemma objectives. We visualise the shortest and most prominent (in our judgement) paths between policies and the trilemma objectives. These are the causal paths with either the fewest connections according to the final map, or which we felt were most important. We arrived at this combination of shortest and prominent paths through iterative discussion. This relies on subjective judgement, which we try to make clear when discussing the path maps. This allows us to focus on the most important and direct causal pathways in the map, but also potentially ignores longer or indirect paths that may be just as, or more, important.

Despite this risk, it is useful to focus on these paths, since we have a large map and exploring all paths between policies and the trilemma would be overwhelming and potentially infeasible.

This combination of analyses for the trilemma allows us to explore how longer-term and dynamic thinking, via feedback loops, complements or contradicts the more direct, intuitive causal paths. We close the section by summarising these analyses and reflecting on some of the salient and recurring features.

Coal capacity payments and the trilemma

In this section, we analyse the impacts of the coal power capacity payment policy (see Chapter 2 for more on this policy) on the energy trilemma objectives via both feedback loops and direct causal paths. Figure 3-2 shows a simplified submap illustrating the feedback loops that mediate the effect of coal capacity payments on the trilemma.

It shows:

- Two feedback loops are present around coal profitability and generation: a dampening loop in which changes in coal generation are dampened by the resulting impact on CEA (carbon emissions allowance) prices; and a reinforcing loop in which changes in coal generation affects future supply of permits in the ETS in the same direction, introducing a reinforcing effect. In this diagram, we explore effects on coal power profitability in aggregate, which abstracts much of the complexity associated with the ETS's different impacts on efficient and inefficient coal generation. Furthermore, these loops simplify a tangled set of multiple feedback loops present in the overall map that involve coal power profitability and generation. These interactions are discussed in more detail in Chapter 2.
- Coal capacity payments interact with these loops in two ways:
  - First, capacity payments directly increase coal power profitability, so suggest an increase in coal power generation, which then triggers the two feedback loops.
  - Second, capacity payments introduce the potential for coal plants to operate with fewer hours and so reduce overall generation. This then plays into the two feedback loops, but in an opposite direction to the direct impact of payments on profitability.
- The overall impact on emissions and supply security will depend on which impact (operating on fewer hours or higher profitability) is stronger, and on which feedback loop (the reinforcing or dampening loop between coal power generation and profitability) is stronger. Note that in a liberalised electricity market, the price would tend to be set by the operating cost of the most expensive plant required, in which case the value of capacity payments would not be offset by

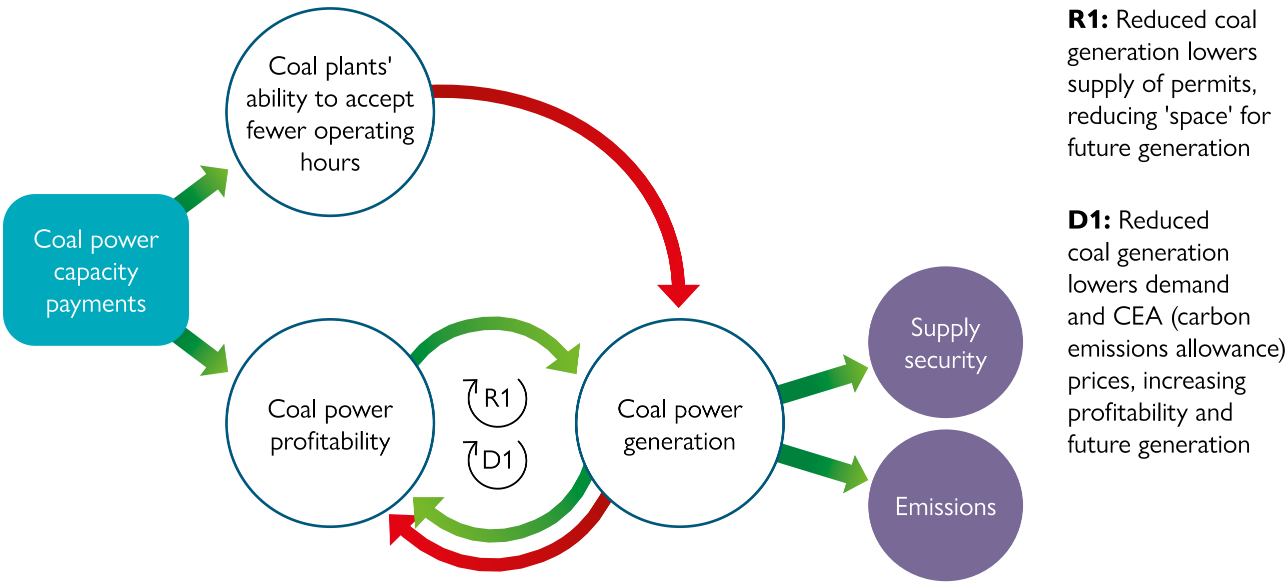


Figure 3-2: Summary of how coal capacity payments influence the energy trilemma via feedback loops.
Note: This submap shows a simplified set of relationships from the full map, covering the paths from coal capacity payments through feedback loops in the map to the trilemma outcomes. Green arrows indicate a positive relationship (i.e. factors move in the same direction) and red arrows indicate a negative relationship (i.e. factors move in opposite directions). White nodes represent variables in the system. Blue rectangular nodes represent policy factors. Purple nodes represent energy trilemma outcome variables. The letters "R" and "D" denote reinforcing and dampening feedback loops, respectively.

reduced electricity prices—and hence would directly increase profitability of coal plants (with no offsetting reduction in prices).

- A short connection to consumer prices is present in the full map, but does not involve feedback loops, so does not appear in the Figure 3-2 submap.

Now, we conduct our shorter path analysis between coal power capacity payments and the trilemma objectives—see Figure 3-3 below. Here, we observe the following:

- The increased fixed revenue for coal from the payment creates three paths of interest:
  - An upward pressure on emissions, via more profitability for inefficient coal power, reduced substitution into efficient coal and VRE, and a higher emissions factor (or a failure to realise improvement in this metric) for the coal fleet.
  - There is also a potentially counterintuitive downwards pressure on emissions created by the fact that coal plants could in principle operate on fewer hours with the payments, which would reduce generation. This effect would only be realised, however, if other policies reduced the incentive or opportunity for coal plants to maximise their generating hours.
  - An increase in security of supply by supporting more coal power capacity.
- Separate from these effects, the capacity payments create extra system costs, which increases consumer prices.

There are some clear overlaps between the feedback loop and causal path analyses for coal capacity payments. One striking pattern in both is the suggestion that coal capacity payments could lead to lower emissions via fewer operating hours. However, this effect would likely only be realised if other policies acted to expand VRE generation or drive down coal power generation. As such, the capacity payments can, at best, be considered an enabler, rather than a driver, of emissions reductions. It is likely that the payments, at least in their current form, may actually increase emissions, as described in the above direct path analysis, the reinforcing feedback loop in Figure 3-2, and in Chapter 2.

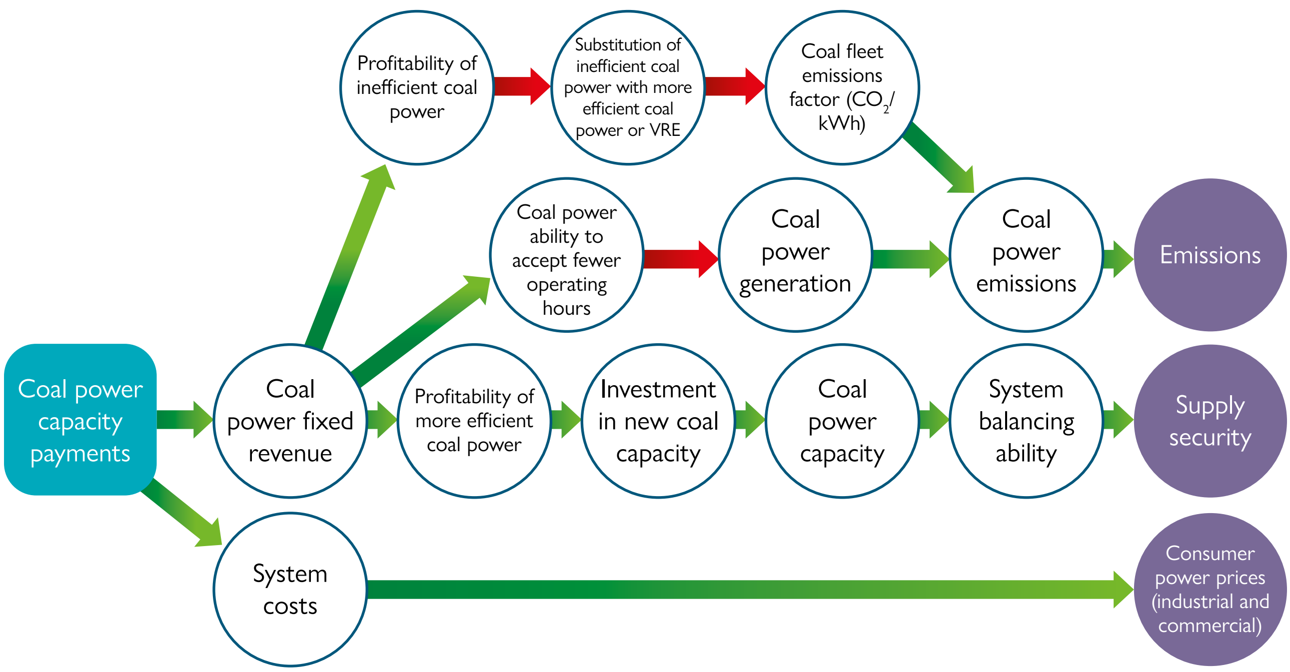


Figure 3-3: Direct paths diagram between coal power capacity payments and the energy trilemma.
Note: This submap shows a combination of shortest and most prominent (in our judgement) paths from coal capacity payments to each of the three legs of the trilemma. Green arrows indicate a positive relationship (i.e. factors move in the same direction) and red arrows indicate a negative relationship (i.e. factors move in opposite directions). White nodes represent variables in the system. Blue rectangular nodes represent policy factors. Purple nodes represent energy trilemma outcome variables.

Chinese regulators have been exploring the possibility of implementing market-based capacity mechanisms for several years,[1] as discussed in Chapter 2, and it is interesting to consider how a transition to such an arrangement would affect the causal pathways described in Figures 3-2 and 3-3. A market-based capacity remuneration mechanism would still have a positive impact on supply security, assuming capacity targets are correctly calibrated, but that security may be delivered by low(er)-carbon sources. A capacity market would reduce system costs compared to the current blanket payment mechanism by procuring only as much capacity as is deemed necessary for security, and doing so in a cost-effective way via auctions. A capacity market may also result in lower emissions by procuring low-carbon capacity and removing support for inefficient coal power units.

Energy storage mandate and the trilemma

China's energy storage mandate policy is now being abandoned, per the new policy *Document 136*[2], issued by NDRC and NEA in February 2025. We retain our analysis of its dynamic effects here, since the points this illustrates may be relevant to the design of future policies intended to support the deployment of energy storage. First we consider the energy storage mandate's effect on the energy trilemma objectives as mediated by feedback loops, shown in Figure 3-4.

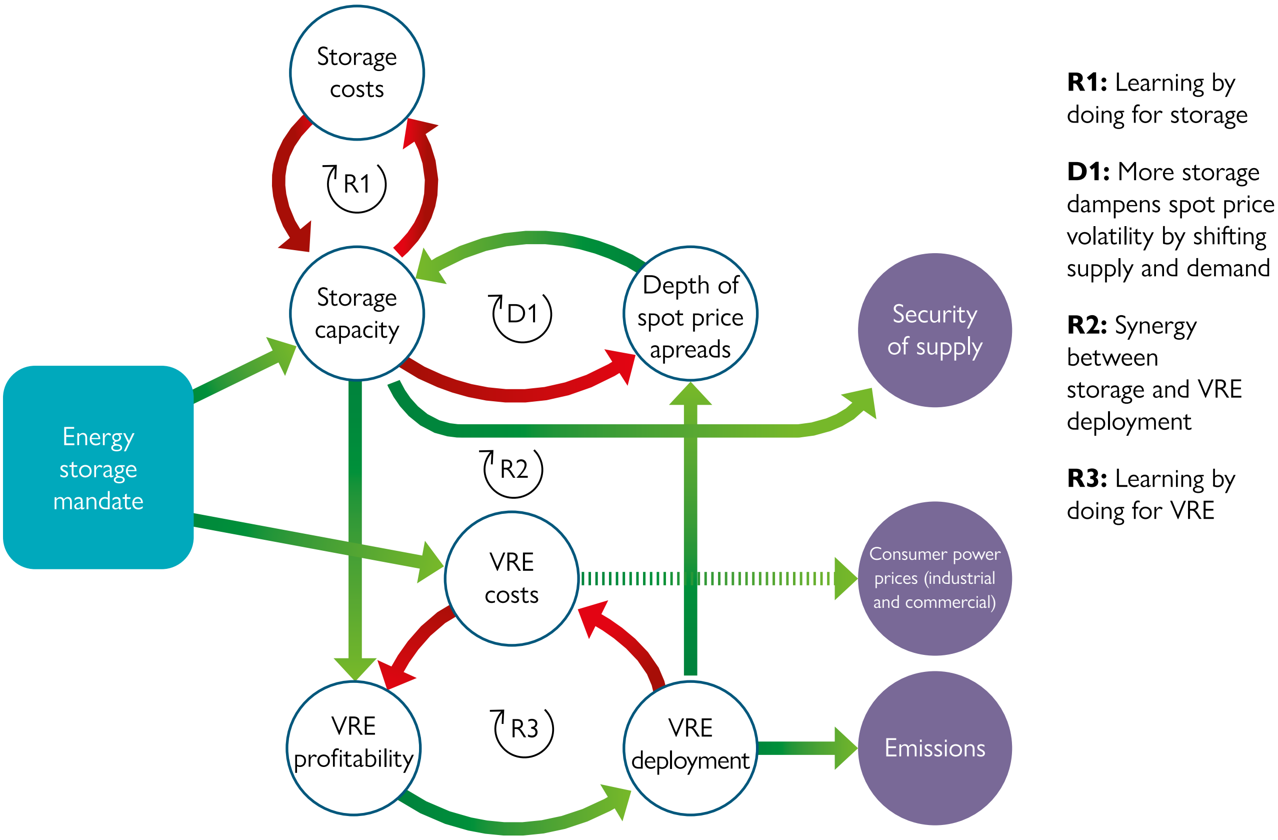


Figure 3-4: Summary of feedback loops that connect the energy storage mandate policy to trilemma outcomes.
Note: This submap shows a simplified set of relationships from the full map. Green arrows indicate a positive relationship (i.e. factors move in the same direction) and red arrows indicate a negative relationship (i.e. factors move in opposite directions). Dashed arrows represent weak or conditional relationships. White nodes represent variables in the system. Blue rectangular nodes represent policy factors. Purple nodes represent energy trilemma outcome variables. The letters "R" and "D" denote reinforcing and dampening feedback loops, respectively.

[1] For example, since NDRC's *Notice on further deepening market-oriented reform of coal power on-grid prices* (发改价格[2021]1439号).

[2] NDRC and NEA (2025). *Notice on deepening market-oriented reforms of new energy on-grid pricing and promoting the high-quality development of new energy*. 发改价格[2025]136号.

The following effects can be seen:

- The energy storage mandate strengthens the reinforcing feedback between storage deployment and storage costs (learning by doing). Storage deployment increases system balancing ability, with a positive effect on security of supply.
- The increase in storage capacity boosts VRE profitability (by reducing curtailment), thus strengthening the reinforcing feedback of VRE deployment and cost reduction (learning by doing), which can lead to lower consumer power prices (subject to market conditions). However, this is potentially offset by the mandate's direct effect on increasing VRE costs.
- Perhaps most importantly, the mandate helps to drive a reinforcing feedback between storage deployment and VRE deployment, in which each technology increases the profitability of the other, ultimately driving down emissions by scaling up VRE. This interacts with another reinforcing feedback in which VRE deployment drives the substitution of inefficient coal plants for VRE (not shown here, but illustrated in Figure 3-14 and discussed in Section 4 below), contributing to emissions reduction. These effects are somewhat offset by, and could even be counteracted by, the mandate's direct effect on increasing the cost of VRE deployment, insofar as slower VRE deployment delays emissions reductions. As discussed in Chapter 2, allocating storage costs to all users of the system instead of only VRE generators could neutralise this unhelpful effect and allow this synergistic reinforcing feedback between storage and VRE to operate more strongly.

Next we consider the direct paths in the system map from the energy storage mandate to the trilemma objectives (Figure 3-5). These display the following salient features:

- A direct impact increasing security of supply via increased storage capacity and system balancing.
- A direct impact increasing consumer prices via increased VRE costs and storage capacity increasing system costs. The longer-term intended impact of the policy on lowering total costs via reduced storage costs and greater integration of VRE (displacing thermal generation) is hidden when we take this shortest path approach.

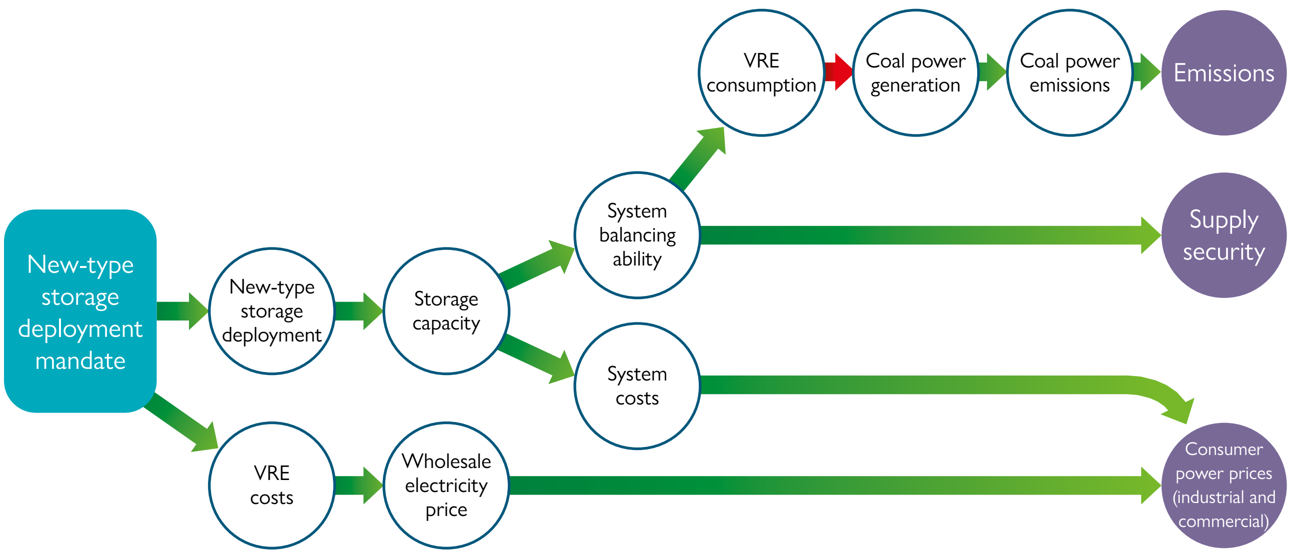


Figure 3-5: Direct paths diagram from new-type energy storage mandate and the energy trilemma objectives.
Note: This submap shows a combination of shortest and most prominent (in our judgement) paths from the new-type storage mandate to each of the three legs of the trilemma. Green arrows indicate a positive relationship (i.e. factors move in the same direction) and red arrows indicate a negative relationship (i.e. factors move in opposite directions). White nodes represent variables in the system. Blue rectangular nodes represent policy factors. Purple nodes represent energy trilemma outcome variables.

- A longer path into reducing emissions, through increasing the system's ability to absorb higher levels of VRE, and the resulting reduction in coal power emissions.

Both forms of analysis suggest the energy storage mandate acts to enhance security of supply, assuming that there is a positive causal link between energy storage capacity and system balancing ability. In practice, this will only be the case if storage capacity is effectively utilised in a way that enhances flexibility. As discussed in Chapter 2, this may not have been the case in practice, as many battery energy storage systems built due to this policy were underutilised[3].

Market liberalisation and the trilemma

In this section, we examine the potential impacts of market liberalisation on the energy trilemma objectives, including via both feedback loops and direct paths, using the two market liberalisation policy factors in the map—the percentages of coal power and VRE generation that are sold via market channels. Figure 3-6 is a simplified version of the full map, focussed only on the market liberalisation policy factors and their causal paths via feedback loops to the trilemma objectives.

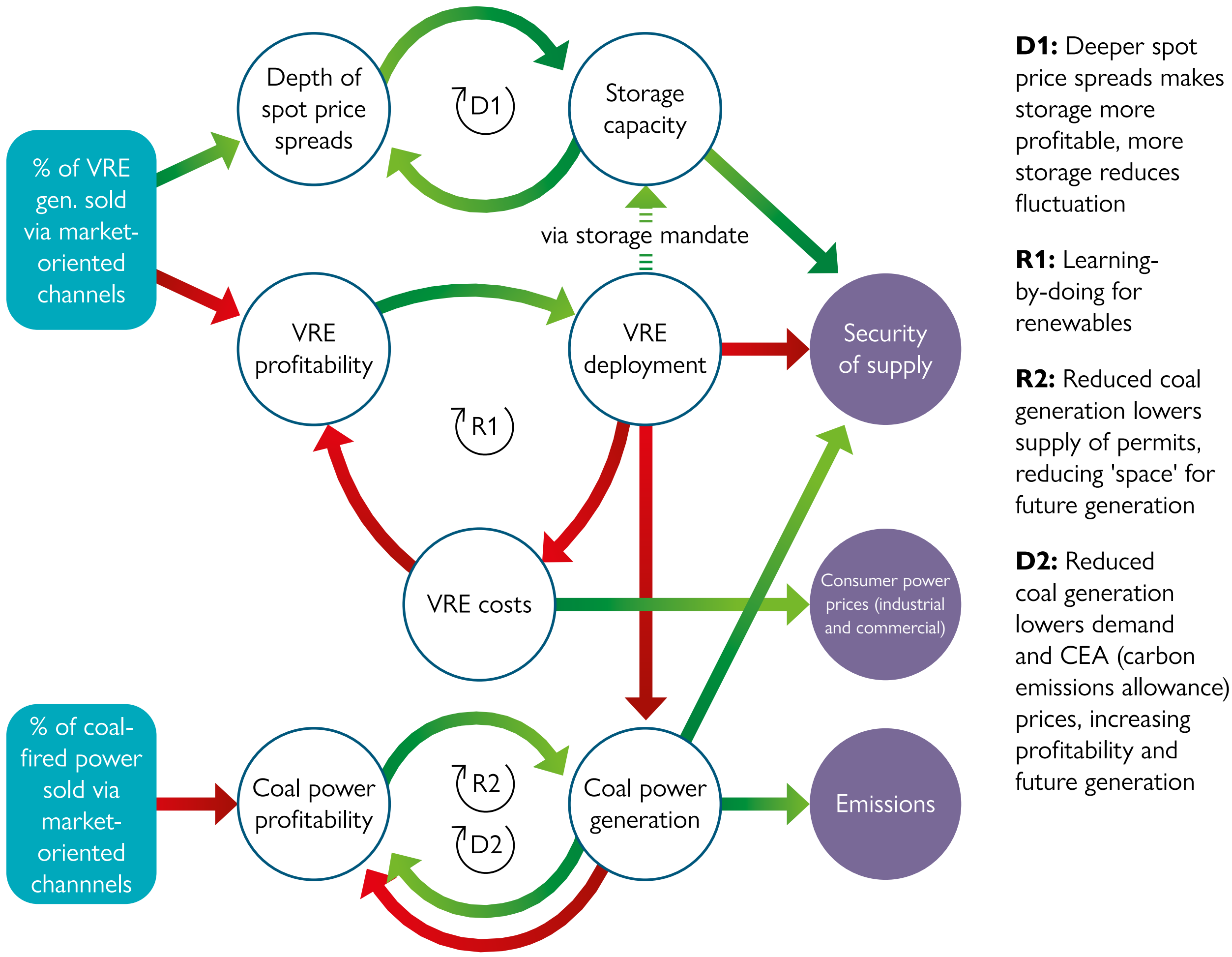


Figure 3-6: Summary of the impact of market liberalisation policies on the energy trilemma via feedback loops.
Note: This submap shows a simplified set of relationships from the full map, which cover the path from percentage of VRE and coal power sold through markets, through feedback loops in the map, to the trilemma nodes. Green arrows indicate a positive relationship (i.e. factors move in the same direction) and red arrows indicate a negative relationship (i.e. factors move in opposite directions). Dashed arrows represent weak or conditional relationships. White nodes represent variables in the system. Blue rectangular nodes represent policy factors. Purple nodes represent energy trilemma outcome variables. The letters "R" and "D" denote reinforcing and dampening feedback loops, respectively.

[3] See *2023 Electrochemical energy storage station industry statistics and data.*

We observe the following interesting patterns:

- We immediately see a complex set of influences into the trilemma, with supply security and emissions being pushed in both directions by different feedback loops. Power prices are only influenced via the learning-by-doing feedback loop (R1 in Figure 3-6) for renewables, since coal power prices are not subject to any feedback effects in our map (coal power generation does not experience meaningful cost reductions via learning-by-doing effects).
- Increasing market-based trading of VRE influences the feedback loops in two ways:
  - First, by increasing VRE's share of generation in spot markets, it increases fluctuation in spot prices, which increases the profitability and deployment of energy storage, which improves security of supply. There is also a natural dampening loop here: as more energy storage and demand-side response are deployed, the need for their further deployment decreases.
  - Second, it reduces VRE profitability, mainly via increased cannibalisation of renewable profits. This undermines the powerful learning-by-doing reinforcing loop which drives cost reductions and increased deployment of renewables. Slower VRE deployment will also necessitate higher levels of coal generation to meet demand, which would increase emissions. It will also undermine the price reductions VRE might offer.
- The increase in coal power being sold via market channels also has potentially nuanced impacts:
  - Promoting market-oriented trading should compete away coal power profits, putting downwards pressure on coal-fired generation and emissions. This may be especially true if competition between technologies is strengthened, for example by expanding economic dispatch.
  - However, there is also a dampening loop in the map (feedback loop D2 in Figure 3-6, whereby reduced coal power generation lowers demand for emissions permits and reduces permit prices, which in turn could weaken decarbonisation incentives for less efficient coal plants, increasing emissions. This effect is probably quite weak, however.
  - Furthermore, there is also a potential reinforcing loop here (feedback loop R2 in Figure 3-6), whereby reduced coal power generation may reduce the supply of emissions permits, driving the carbon price up and threatening the profitability of inefficient coal power plants.

Now, we turn to our direct path analysis for market liberalisation. We again take the two factors in the map representing the percentage of coal and VRE generation sold via market channels and look for the paths to the trilemma objectives (Figure 3-7). We see the following salient features:

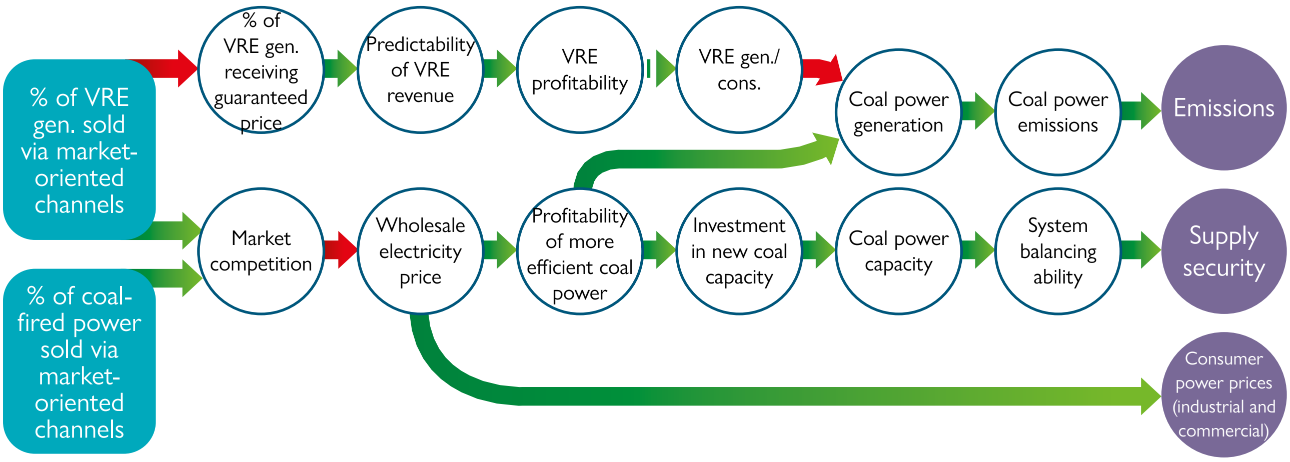


Figure 3-7: Direct paths diagram from market liberalisation policies to the energy trilemma. Note: This submap shows a combination of shortest and most prominent (in our judgement) paths from percentage of power sold via the market for coal and renewables respectively, to each of the three legs of the trilemma. Green arrows indicate a positive relationship (i.e. factors move in the same direction) and red arrows indicate a negative relationship (i.e. factors move in opposite directions). White nodes represent variables in the system. Blue rectangular nodes represent policy factors. Purple nodes represent energy trilemma outcome variables. The dotted arrow from VRE profitability to VRE generation and consumption represents the fact that there are multiple steps between these in the full map.

- An increase in market competition in this simplified representation reduces wholesale electricity prices, which drives three distinct routes into the trilemma:
  - A direct reduction in consumer prices following the reduction in wholesale prices.
  - Lower emissions via a reduction in the profitability and generation of coal power—that is, coal power would be increasingly outcompeted in the generation mix.
  - A reduction in security of supply via reduced investment and capacity in coal. This may be a legitimate concern and part of the rationale for the coal power capacity payments: coal power profitability could indeed fall due to liberalisation and VRE substitution. However, other liberalising measures that occur in parallel, such as strengthening cross-provincial connectivity and demand-side price signals, could work to enhance security of supply.

In practice, increasing market competition may not reduce wholesale prices: if the effect is to move the system from average cost to marginal cost pricing, the net effect may be to increase wholesale prices.

- Less directly, but perhaps of critical importance, is the effect of market liberalisation on the deployment of variable renewable power. We include a longer chain at the top of the figure, showing how a reduction in guaranteed prices tends to reduce the stability of revenues for renewables (which could be further reduced as larger volumes of renewables increase spot market volatility and the frequency of periods with very low prices, as discussed in Chapter 1). This could reduce renewables deployment and generation, leading to higher coal generation and emissions over time. Since renewables are becoming the lowest cost form of generation, this effect could also limit the extent to which market liberalisation is able to reduce system costs and prices.

Interprovincial connectivity and the trilemma

In this section, we consider the potential impacts of enhancing cross-provincial interconnection on the energy trilemma objectives. Figure 3-8 shows the effect of this policy on relevant feedback loops.

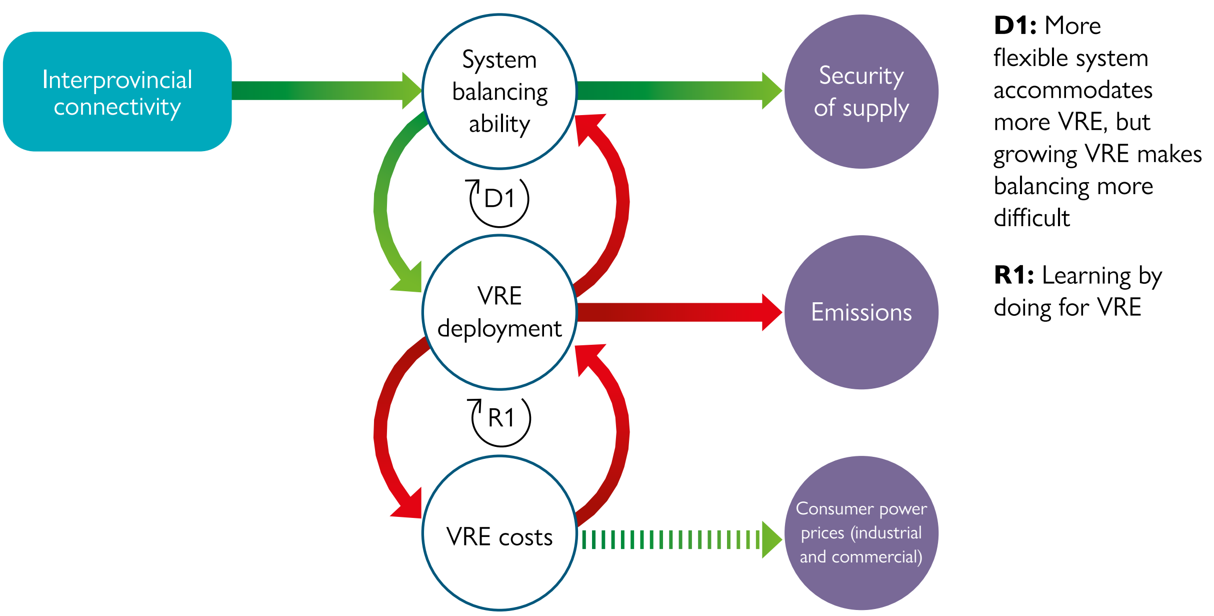


Figure 3-8: Summary of feedback loops that connect the policy of enhancing interprovincial connectivity with energy trilemma outcome variables.
Note: This submap shows a simplified set of relationships from the full map. Green arrows indicate a positive relationship (i.e. factors move in the same direction) and red arrows indicate a negative relationship (i.e. factors move in opposite directions). Dashed arrows represent weak or conditional relationships. White nodes represent variables in the system. Blue rectangular nodes represent policy factors. Purple nodes represent energy trilemma outcome variables. The letters "R" and "D" denote reinforcing and dampening feedback loops, respectively.

The following effects can be seen:

- Enhancing interprovincial connectivity improves system balancing ability, as it allows generation resources to be pooled over a greater geographical area. This enhances security of supply.
- A more flexible system enabled by interprovincial connectivity will be able to absorb more VRE generation, driving up VRE deployment, which reduces emissions. We note, however, that there is a dampening feedback loop (D1 in Figure 3-8) representing the limits of safe VRE integration for a given level of system flexibility.
- By enabling greater deployment of VRE, the policy can also contribute to strengthening the learning by doing feedback loop that drives ongoing cost declines in VRE, putting downwards pressure on costs over the long term.

Next we consider the direct impacts on trilemma objectives of increasing investment in cross-provincial transmission together with harmonisation of provincial regulations (Figure 3-9). This map includes the following features:

- An increased size of balancing area has several proximate impacts, including:
  - A direct increase in security of supply.
  - Competing effects on costs: the construction of transmission infrastructure could add costs into the system, but the economies of scale created by a larger system could work in opposition to this effect.
- A longer causal chain cuts emissions by reducing coal power generation and capacity because of increased market competition. There is also another potential impact, not shown, whereby increasing the system's ability to absorb higher levels of renewables (reducing curtailment) may promote the substitution of coal power with VRE. The reduced coal power capacity could have some negative effect on security of supply if not offset by increased system flexibility as described above.

The features in this map highlight some of the potential advantages of expanding cross-provincial connectivity. Security of supply is directly enhanced, as grids can

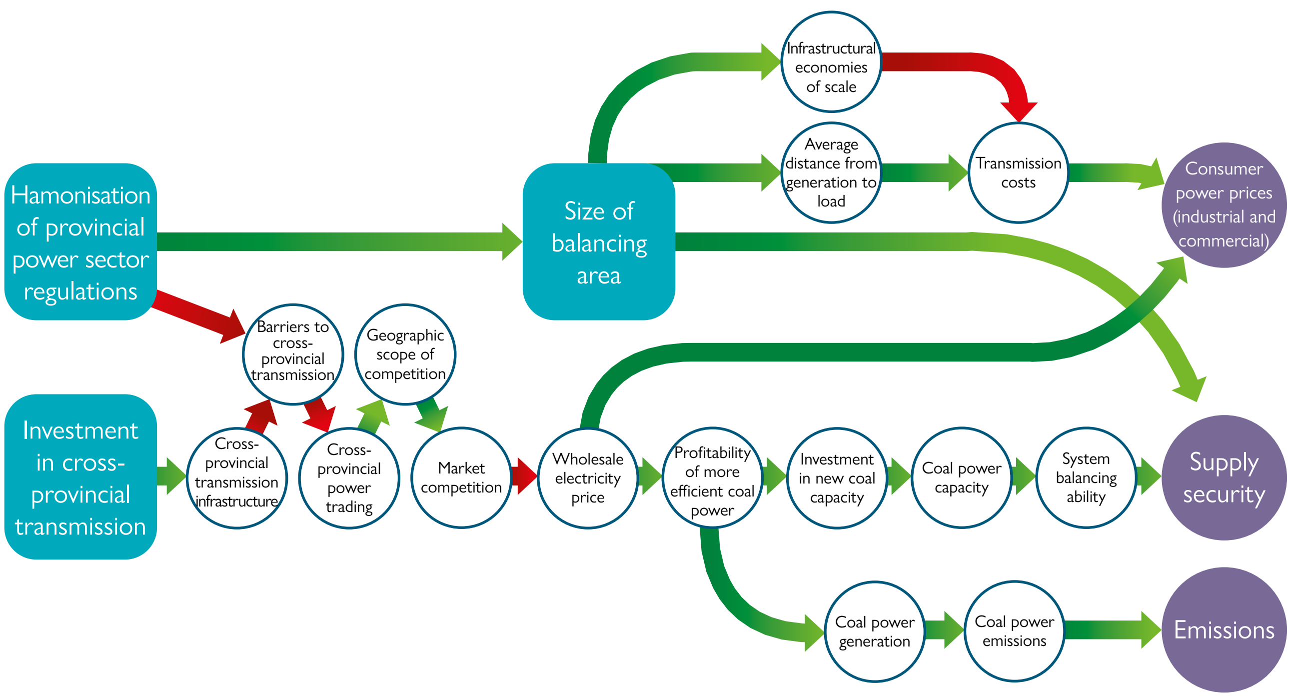


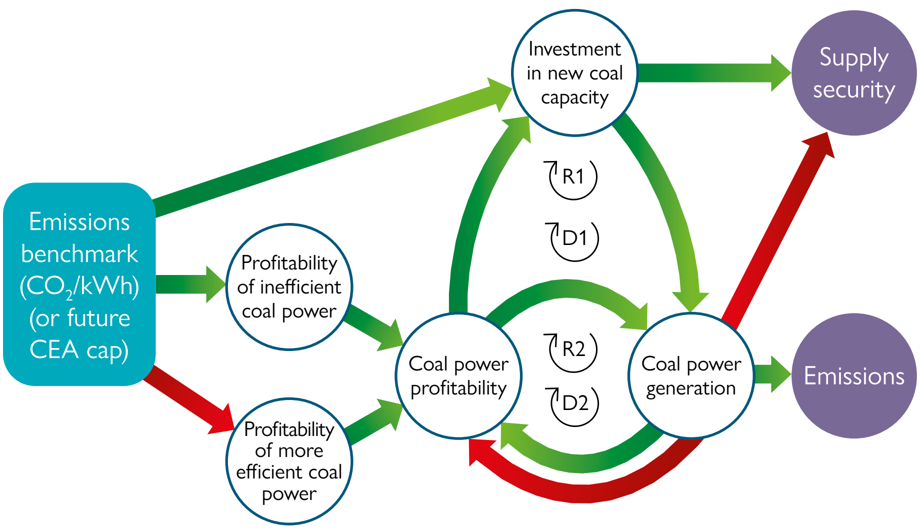
Figure 3-9: Direct paths diagram between interprovincial connectivity policy factors and the energy trilemma objectives.
Note: This submap shows a combination of shortest and most prominent (in our judgement) paths from harmonisation of provincial regulation and investment in cross-provincial transmission to each of the three legs of the trilemma. Green arrows indicate a positive relationship (i.e. factors move in the same direction) and red arrows indicate a negative relationship (i.e. factors move in opposite directions). White nodes represent variables in the system. Blue rectangular nodes represent policy factors. Purple nodes represent energy trilemma outcome variables.

draw from a wider range of generation sources to meet demand. On prices, besides the proximate effects described in the above analysis, strengthening cross-provincial connectivity will tend to drive down prices by sharing resources, expanding the geographical scope of market competition, and allowing demand to be met by the lowest-cost generation mix selected from a wider pool of sources. This effect is likely to be powerful, implying that strengthening connectivity would ultimately drive down costs. While not shown on the diagram, enhancing interprovincial connectivity could also drive down emissions by reducing curtailment and allowing low-cost renewable power to meet demand across a broader geographical scope (IEA, 2023). As such, strengthening cross-provincial connectivity could potentially benefit all three trilemma objectives.

The emissions trading scheme and the trilemma

In this section, we again conduct the same feedback loop and direct path analysis for the emissions trading scheme (ETS). Figure 3-10 shows how the lowering the ETS benchmark (i.e. allocating fewer CEAs to plants per MWh generated) impacts feedback loops leading into the trilemma. It shows:

- Lowering the ETS benchmark could:
  - Reduce investment in new coal power capacity
  - Reduce profitability of inefficient coal
  - Increase profitability of more efficient coal
- These three effects then influence two of the ETS-related feedback loops around coal profitability and generation mentioned in 2.1 and 2.2; a dampening loop via CEA prices, and a reinforcing loop via CEA supply.
- Coal profitability is pushed in both directions by the ETS because of the differing impacts on more and less efficient coal plants. This effect arises from the configuration of the Chinese ETS: CEAs are allocated freely to emitters, so the scheme does not impose extra costs on the coal power sector as a whole. Instead, under this arrangement, inefficient plants must pay to purchase CEAs, whereas efficient plants can



D1: Reduced investment in new coal lower generation, which lowers CEA (carbon emissions allowance) demand and prices, incrcasing profitability and future potential investment

D2: Reduced coal generation lowers CEA demand and prices, increasing profitability and future generation

R1: Reduced coal investment lowers generation, which lowers supply of permits, reducing 'space' for future generation

R2: Reduced coal generation lowers supply of permits, reducing 'space' for future generation

Figure 3-10: Summary of how the ETS influences the energy trilemma objectives via feedback loops.
Note: This submap shows a simplified set of relationships from the full systems map. Green arrows indicate a positive relationship (i.e. factors move in the same direction) and red arrows indicate a negative relationship (i.e. factors move in opposite directions). White nodes represent variables in the system. Blue rectangular nodes represent policy factors. Purple nodes represent energy trilemma outcome variables. The letters “R” and “D” denote reinforcing and dampening feedback loops, respectively.

actually earn extra revenues by selling surplus CEAs (see Chapter 2).

- There is a new pair of related feedback loops, one dampening and one reinforcing, via investment in new coal capacity, coal generation, and coal profitability (R1 and D1 in Figure 3-10).
- The impact of tightening the ETS emissions benchmark on security of supply and emissions is mediated by this complex set of feedback loops, there is no clear direction of the impact. In practice, this is probably true and configured by policymakers deliberately as such in order to avoid driving coal power plants out of the market, which would reduce security of supply (in the short-medium term at least). In the future, if coal power were phased down as a result of ETS reform (e.g. if CEAs were auctioned), then this may need to be accompanied by complementary policies to ensure sufficient capacity and flexibility were available elsewhere in the system.
- There is no connection into consumer prices via a feedback loop.

Now, we again conduct an analysis of direct causal paths that link adjustments to the ETS emissions benchmark to the energy trilemma outcome variables. The ETS benchmark factor has three main paths into the trilemma factors (Figure 3-11). If we assume a reduction in the carbon intensity benchmark (i.e. a stricter emissions standard), we see:

- Some ambiguous effects due to the different impacts of the ETS on more efficient and less efficient coal plants:
  - We observe an ambiguous effect on security of supply via reductions in inefficient coal plant investment and capacity, but more investment in efficient capacity (as a tighter benchmark would reduce CEA supply and allow these plants to sell surplus CEAs at higher prices). In Figure 3-11 below, only the former effect (i.e. reduced investment in coal power) is depicted, as we assume that it would be stronger than the latter.
  - An ambiguous effect on prices: the policy imposes extra costs on inefficient coal plants but subsidises more efficient coal plants, with little if any overall

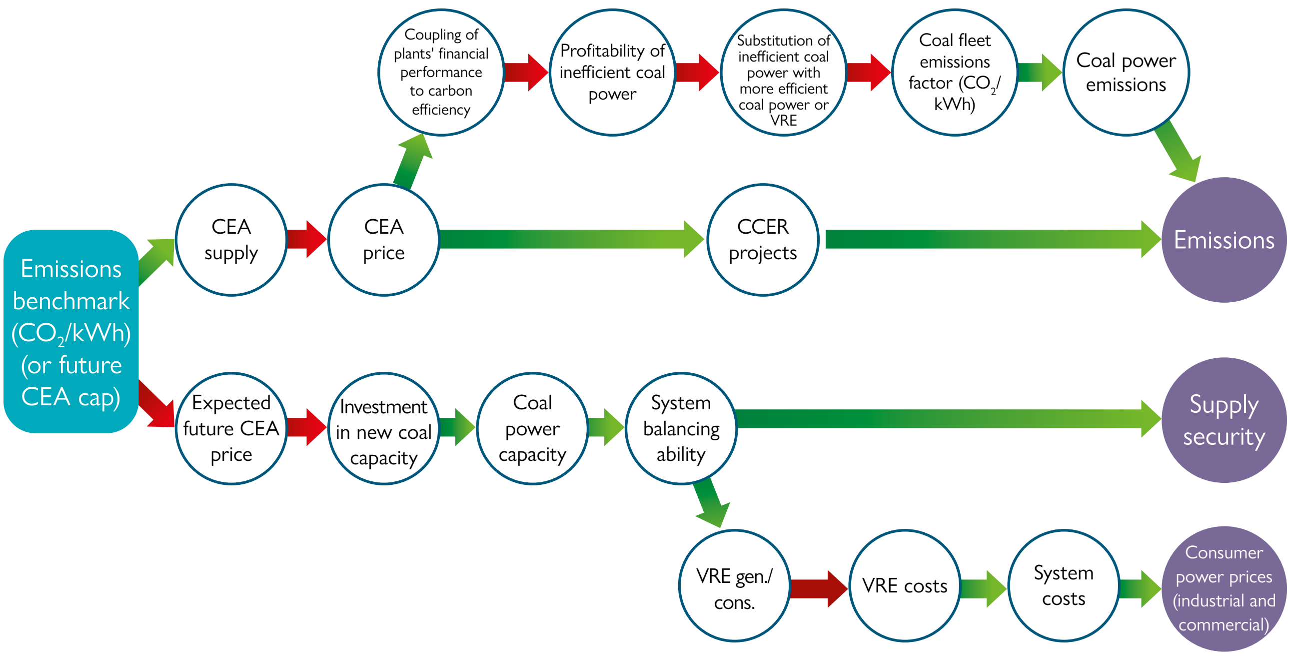


Figure 3-11: Direct paths diagram between adjustments to the ETS benchmark and the energy trilemma outcome variables.
Note: This submap shows a combination of the shortest and most prominent (in our judgement) paths from the ETS benchmark to the three legs of the trilemma. Green arrows indicate a positive relationship (i.e. factors move in the same direction) and red arrows indicate a negative relationship (i.e. factors move in opposite directions). White nodes represent variables in the system. Blue rectangular nodes represent policy factors. Purple nodes represent energy trilemma outcome variables.

net cost for the thermal power sector as a whole. Indirectly, if it accelerates substitution of (inefficient) coal power with VRE, this could reduce costs, although the map also shows how weaker system balancing could limit VRE integration, which may delay cost reductions.

- A direct reduction in emissions via encouragement of CCER projects. However, a longer causal chain, but one which we believe will be a much stronger influence on emissions, is the higher CEA price leading to substitution of inefficient coal power generation with more efficient coal generation and VRE (shown at the top of Figure 3-11).

As discussed in Chapter 2, the ETS so far has generated only very low prices for emissions permits—around 92¥/ tCO_2 in 2024,[4] imposing costs (on the less efficient coal generators) that are generally far outweighed by the cash injections of coal capacity payments—and the dampening feedback loops inherent in its design tend to keep permit prices low. Without policy adjustments to generate higher CEA prices, and probably to include an element of auctioning, the magnitude of each of the effects discussed above is likely to be minimal.

Summary of policy impacts on the trilemma

In this section, we summarise the feedback loop and path analyses presented above. While there is much unresolved uncertainty in this analysis, and different stakeholders hold differing views on the relevance of various influences, feedback loops, and causal chains in the map, it is clear that many policies involve trade-offs to some degree. None of the policies studied appear to clearly benefit all three objectives via both direct paths and feedback loops, as outlined in Table 3-1.

Table 3-1: Summary of impacts of policies on the energy trilemma objectives from path and feedback loop analyses
Note: Desirable impact on a trilemma objective (e.g. lowering costs) are shown by the colour of the cell, green = desirable, red = undesirable, grey = ambiguous effect, white = no effect. The logic of the impact is explained by the text in the cell.

Policy	Lowering costs		Ensuring security of supply		Reducing emissions	
	Paths	Feedback loops	Paths	Feedback loops	Paths	Feedback loops
Coal capacity payments	Increased system costs	No influence through feedback loops	More coal power	More coal generation if plants needed for additional generation, but potential for dampening feedback	Mixed impacts—more coal power capacity but potential for reduced operation	Emissions rise if more coal generation, but potential for dampening feedback
Energy storage mandate	Increased system costs and VRE costs	More VRE integration, promoting ongoing cost reduction	More storage	More storage, also via reinforcing feedback of storage cost reduction	More VRE integration	Mixed impacts—more storage supports higher VRE integration, but extra VRE costs slows deployment
Market liberalisation	More competition, ambiguous impacts arising from marginal prices and indirect effects	Undermining VRE learning-by-doing increases prices (if liberalisation slows VRE deployment)	Less coal power but greater cross-provincial trade and demand-side measures	More value in storage and DSR	Less coal power, but also pressure on renewables	Complex dynamics by limiting VRE deployment but reducing coal
Interprovincial connectivity	Mixed impacts—higher costs from building transmission, but lower from economies of scale and stronger competition	Enables more VRE deployment, driving down costs	Expands geographic scope of supply resources, but also competing effect if coal is driven out	Expands geographic scope of supply resources	More competition drives coal power out of mix	Enables higher VRE consumption
Tightening emissions benchmark in ETS	Ambiguous effect via differing impacts on efficient and inefficient coal	No influence through feedback loops	Ambiguous effect via differing impacts on efficient and inefficient coal	Lower investment in coal capacity, but also mixed impacts on coal generation	More efficient coal plants and VRE	Complex dynamics depending on different impacts on more and less efficient plants, and competing feedbacks

[4] Per statistics quoted in *People's Daily*.

There are also several common feedback loops and pathways in the maps that link our policies of interest with the trilemma objectives. In terms of feedback loops, the two loops (one reinforcing, one dampening) that act through the ETS to influence coal power profitability and generation appear to mediate the relationship between three of the five policies examined and the two trilemma outcomes of carbon emissions and security of supply (see Figures 3-2, 3-6, and 3-10). However, due to the low level of the CEA price currently, we do not believe that these feedback loops play a major role in determining energy trilemma outcomes—although this could change if the ETS were adjusted to impose higher costs on emitters. If that were to occur, and barring other design modifications, unpicking which of these two loops is more likely to dominate at any given time would be key to more detailed analyses.

The learning by doing feedback loop for VRE that drives ongoing cost declines and deployment also mediates the relationship between three of the five policies investigated and the trilemma objectives. This feedback loop drives down emissions and costs, supporting two of the three trilemma objectives, and it is therefore important that policy strengthens and supports this feedback loop.

In terms of direct pathways, first, we see coal power investment, profitability, generation and capacity as common mediators. Many of the potential influences described above affect emissions via coal generation. This serves to remind us, as is portrayed in the map, that only displacement of coal generation (or the application of carbon capture and storage to coal generation) reduce emissions.

Similarly, impacts on security of supply are often linked to coal power capacity or energy storage capacity. This demonstrates a degree of substitutability of these two technologies: both enable the integration of VRE and contribute to security. In the future, energy storage should grow to displace coal power as a source of low-carbon flexibility. A second common direct pathway affecting security occurs via market competition: it is assumed that increased competition between generation technologies would displace coal-fired power in favour of cheap VRE, leading to a reduction in security (of course, this assumes no deployment of other policies to support security).

Table 3-1 summarises the potential direction of relationships between policies and the trilemma objectives described in our feedback loop and paths analysis. Directionality is simplified to indicate whether the policy increases, reduces, or has mixed impacts on each leg of the trilemma. This summarises a set of sometimes quite complex and context-dependent relationships, but gives a sense of the trade-offs between different policies and objectives as captured in the maps.

This combined summary makes clear the trade-offs and uncertainties involved in the impacts of these three policies. We see uncertainty arising both: (i) from within either of the feedback loop or direct path analyses, in cases when we have two competing paths or two competing feedback loops; and (ii) between the two styles of analysis, when direct paths and feedback loops suggest different impacts. The results in Table 3-1 highlight the need to unpick uncertainties and investigate more deeply how feedback loops might play out in practice.

Notwithstanding these uncertainties, there appear to be two forms of intervention that can have positive or neutral effects across all three energy trilemma objectives, if the costs of their implementation are managed carefully. One of these is increasing deployment of energy storage, but with the significant caveat that this will only be the case if storage can be deployed in a way that has a net positive effect on VRE deployment. Historically, the energy storage mandate has increased VRE investment costs, which in our analysis could delay emissions reductions by slowing VRE deployment (see Table 3-1). However, this effect could be sidestepped if the costs of storage deployment are not borne by VRE developers or can be managed in such a way that they do not have to immediately pass on costs to consumers. Such a policy could avoid increasing system costs, and enhance security of supply directly and indirectly contribute to emissions reduction over the long term.

The other potential positive across all three objectives is likely to be enhancing cross-provincial connectivity. Provided the costs of its deployment (e.g. transmission infrastructure costs) are more than offset by its ability to drive down prices through expanding competition and the pool of potential generation resources, which may be achieved by careful regulation of transmission investments, it could reduce costs and emissions as well as increasing security of supply.

The effect of market liberalisation on the energy trilemma objectives is highly uncertain (see Table 3-1) and contingent on many factors. This was one of just two policies (the other being energy storage mandate) for which we saw a direct contradiction between the two forms of analysis. The direct path analysis suggests that more market competition would lower costs, whereas the feedback loop analysis suggests that this would undermine learning-by-doing dynamics in VRE, counteracting cost reductions. The effects on emissions are particularly complex. To ensure that liberalisation leads to both lower prices and emissions, it will be important to prevent cannibalisation effects from slowing VRE deployment, which may be achieved through appropriate contracting structures as described in Section 4 of this chapter and Chapter 1. To achieve a positive effect on security of supply, measures will be needed to ensure new flexibility technologies such as energy storage and DSR can participate fully in markets, as described in Chapter 2.

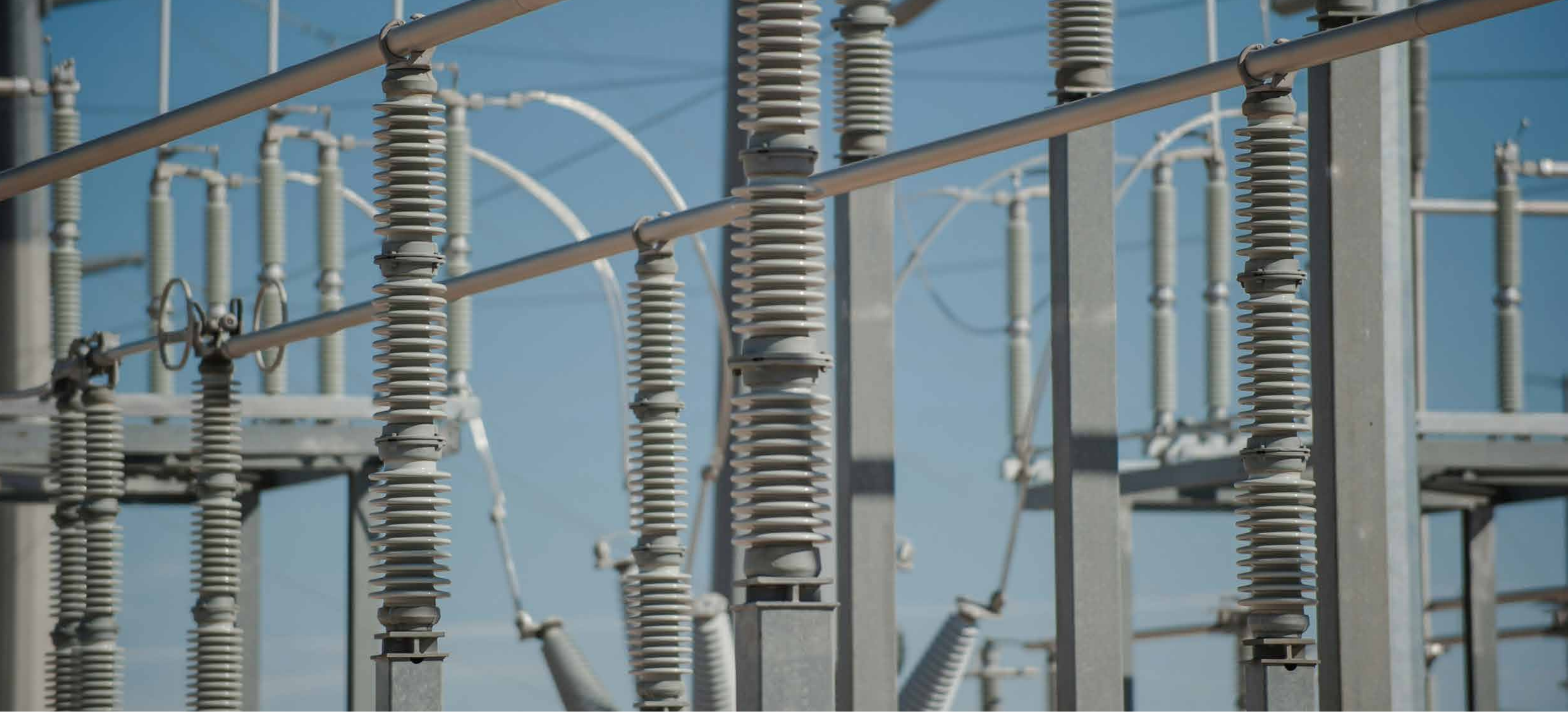
Using feedback loop and shortest path analyses

The above analysis of feedback loops highlights a vital point when thinking dynamically about systems. It makes clear that trilemma outcomes are influenced by several feedback loops. The key questions then become: when might one feedback loop dominate another, and when might linear, direct effects be mitigated (or not) by feedback loops?

Key to answering these questions is understanding the potential timing and delay between causal connections. For example, how long does it take for a slowdown in energy storage deployment to increase spot price fluctuation, and then for increased storage capacity to be delivered in response? If this dampening loop is very slow to take effect, it may not drive storage deployment rapidly enough to meet energy policy objectives.

In effect, direct path analysis and feedback loop analysis can be considered two different ways of using system mapping. The first is more static; if we look at direct paths, we generally see short-term impacts. The second is more dynamic; if we look at feedback loops, we generally see longer term impacts, but they are harder to unpick with basic intuition.

This mirrors the broader issue of how to weigh up short/narrow and long-term/dynamic costs and benefits of decarbonisation policy (Mercure et al., 2021). Combining these static and dynamic approaches, as we have started to do here, is likely to be helpful for identifying potential impacts and informing more quantitative analysis, as well as aiding discussion between stakeholders and explaining why they may have different conceptions of the system and how it behaves.



3. Consistency between policy goals

In this section, we use the system map to consider how consistent policy logics and impacts are—that is, we investigate the extent to which different policies' impacts align or conflict with each other.

First, we do this by looking at subsections of the full map which focus only on the causal chains triggered by selected policy factors (i.e. factors 'downstream' of policies). This in effect shows a combined theory of change for multiple policies at the same time.

Second, we zoom in on the profitability of coal power and VRE as key outcomes and examine the impacts on these variables from different policies (i.e. policies 'upstream' of these key outcomes).

Taking this approach helps us focus narrowly on policy impacts and consistency, which came up routinely in our discussions with policymakers and researchers. Chinese power sector governance has been, and continues to be, characterised by a tangled network of overlapping policies and institutions managed by different actors and departments, meaning this coordination question is likely to be of continuing interest.

3.1 Consistency in policies' theories of change

Figure 3-12 shows the impacts caused by a range of policies related to decarbonisation, security of supply, and regional connectivity, chosen here as key policy objectives. The map shows only those factors which are within two causal steps downstream of the policy factors and removes other causal paths. We observe:

- These policies have direct causal impacts on many factors, so effects on outcomes of interest may be mediated by many interactions and causal pathways.
- The policies do interact with similar sets of factors; only one of the policies—investment in cross-provincial transmission—is separated from the others in this view.
- Only one trilemma outcome variable is causally close (within two causal steps) to the policies—consumer prices.
- There are a range of factors which are only being influenced by one policy, or are being pushed in the same direction by different policies; these are shown in white.
- However, there are a range of factors which are being pushed in different directions by different policies (e.g. VRE profitability is increased by raising RPS targets but reduced by the storage mandate). These are highlighted in red, and are described further in Table 3-2.

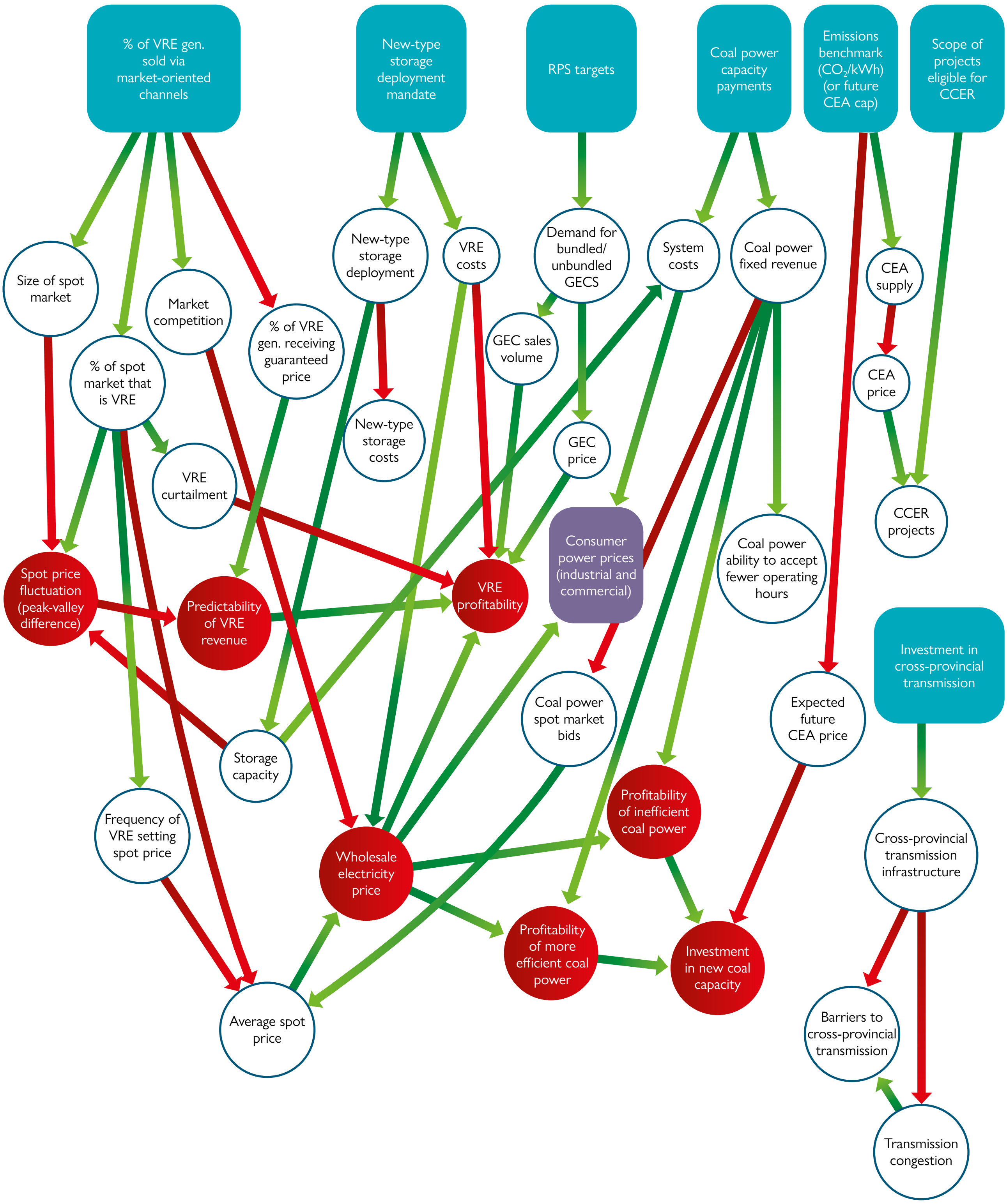


Figure 3-12: Two steps downstream of a selection of policies.
Note: This submap shows the factors and connections within two causal steps downstream from selected policies. The submap shows how various policies might impact certain nodes. Nodes which are being pushed in different directions by policies are highlighted in red. Green arrows indicate a positive relationship (i.e. factors move in the same direction) and red arrows indicate a negative relationship (i.e. factors move in opposite directions). White nodes represent variables in the system. Blue rectangular nodes represent policy factors. Purple nodes represent energy trilemma outcome variables.

Table 3-2: A list of factors being pushed in different directions by different policies in the downstream policy map.
Note: Potentially important inconsistencies are emboldened.

Factor	Policies increasing	Policies decreasing	Comment
Spot price fluctuation	• % of VRE sold via market	• % of VRE sold via market • New-type storage mandate	Complex impacts of market liberalisation are main issue here. Increases in the fluctuation of the % of VRE sold via the market is likely to dominate.
Wholesale electricity price	• New-type storage mandate	• % of VRE sold via market • Coal power capacity payments	New-type storage mandate is the only policy with a short causal chain increasing prices. Coal capacity payments likely to have multiple effects on wholesale and consumer prices – direct increase in system costs, but also facilitate lower coal bids in spot markets.
VRE profitability	• **RPS targets**	• **New-type storage mandate** • **% of VRE sold via market**	**Direct trade-off between decarbonisation and market liberalisation**
Predictability of VRE revenue	• % of VRE sold via market	• % of VRE sold via market	Complex impacts of market liberalisation are main issue here. Market liberalisation likely to cause overall reduction in predictability.
Profitability of more efficient coal power	• **Coal power capacity payments** • **ETS permit price**	• **% of VRE sold via market**	**Direct trade-off between security of supply policy and market liberalisation**
Profitability of inefficient coal power	• **Coal power capacity payments**	• **% of VRE sold via market** • **ETS permit price**	**Direct trade-off between security of supply policy and market liberalisation**
Investment in new coal capacity	• **Coal power capacity payments**	• **ETS emissions benchmark** • **% of VRE sold via market**	**Direct trade-off between security of supply policy, decarbonisation, and market liberalisation. However, the impacts differ, especially of the ETS, whether we are considering efficient or inefficient coal.**

3.2 Policy impacts on the profitability of VRE and coal

In this section, instead of looking downstream from policies, we look upstream of two key outcomes in the power sector: VRE profitability and coal profitability. This helps us to consider any inconsistencies in the policies and other factors driving these outcomes.

Figure 3-13 shows a submap focussed on factors within two steps upstream of VRE and coal profitability; note, coal profitability is split into two factors, one for efficient and one for inefficient coal. We observe:

- Several policies close to these outcomes:
    - The coal power benchmark price affects all three profitability factors. This is true insofar as the on-grid price of VRE is tied to the coal benchmark price (set to change following the release of *Document 136*).
    - Subsidies for VRE and limits on spot market price fluctuations both increase VRE profitability.
    - Coal capacity payments increase the profitability of both efficient and inefficient coal power plants.
- Other interesting phenomena include:
    - The CEA price pushes the two coal profitability factors in different directions, and is, of course, influenced by the ETS emissions benchmark, which is just beyond the scope of this submap.
    - Market competition and average spot price influence the profitability of all generators in the same direction via their effects on wholesale electricity prices.
    - VRE costs present an interesting case. VRE profitability

is influenced by both wholesale prices and VRE costs. VRE costs directly affect VRE profitability (cost declines imply higher profits), but they also have a positive relationship with wholesale prices (VRE cost reductions should decrease prices), which itself has a negative relationship with VRE profitability. This means that changes to VRE costs could push VRE profitability in both directions. In reality, it is likely that when changes in wholesale prices are driven by VRE cost declines, the net effects will push VRE and coal profitability in different directions (decreasing coal power profitability but boosting VRE profitability via the direct effect), whereas when wholesale prices are driven by market competition or spot prices, net effects will drive coal power and VRE profitability in the same direction (e.g. fiercer market competition could compete away profits of all generators).

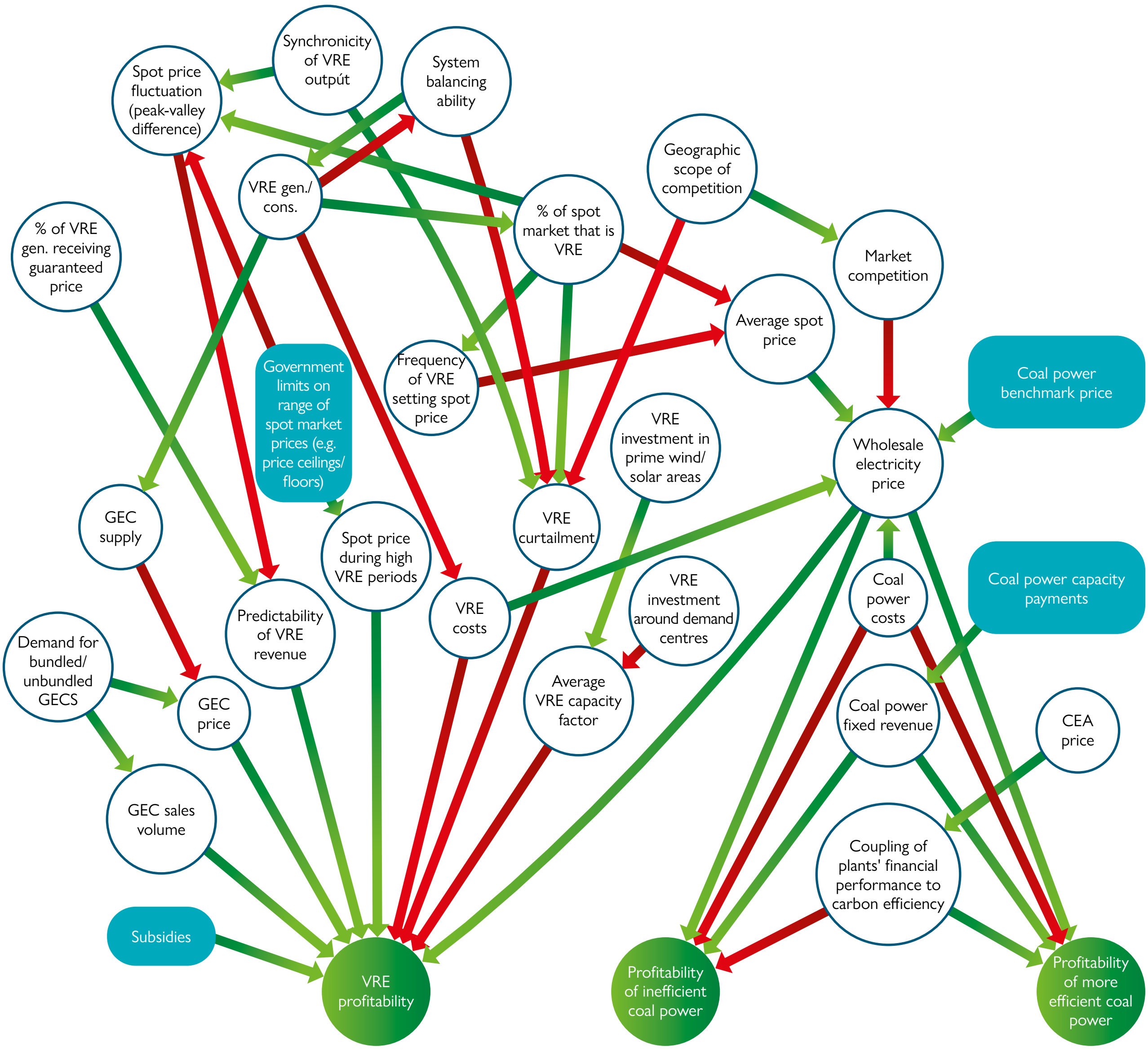


Figure 3-13: Two steps upstream of renewables and coal profitability.
Note: This submap shows the factors and connections within two causal steps upstream of the three factors in the map representing the profitability of (efficient and inefficient) coal power and VRE. The submap shows how policies and general factors might impact profitability. The three profitability nodes are highlighted in green. Green arrows indicate a positive relationship (i.e. factors move in the same direction) and red arrows indicate a negative relationship (i.e. factors move in opposite directions). White nodes represent variables in the system. Blue rectangular nodes represent policy factors.

4. Larger feedback loops in the full map

4.1 Approach to identifying larger feedback loops

China's power sector is characterised by a complex network of relationships between different policies and variables, as presented in our system map. To build on our previous analysis of simpler feedback loops, we analysed the overall system map to discover larger feedback loops. Our intention is to reveal deeper feedback mechanisms that either cut across different policy domains within the power sector (e.g. that connect emissions variables to liberalisation) or link many nodes via longer causal chains.

Systematic analysis of the overall map revealed dozens of these larger, cross-cutting feedback loops. Most of these loops did not offer any meaningful new insights, either because they were already intuitive or because we judged their effects to be extremely weak in practice. This indicates that the key feedback loops within the power system operate largely within identifiable subsystems. However, some interesting dynamics related to technological competition were revealed, as discussed below.

4.2 Competing feedback loops affecting VRE deployment

Analysis of the overall map revealed nested feedback loops that potentially compete to determine whether VRE deployment produces a net dampening or reinforcing effect on future deployment.

The innermost loop, labelled "R1" in Figure 3-14, represents the well-known learning-by-doing feedback loop, as discussed in Chapter 1. This loop is assumed to be relatively strong, driving ongoing cost declines and investment in VRE as cumulative deployment grows.

The effect of this learning-by-doing loop may, however, be offset to some degree by the dampening middle loop of Figure 3-14, labelled "D". This loop represents the cannibalisation effect: increasing VRE penetration puts downwards pressure on power prices, eating into the

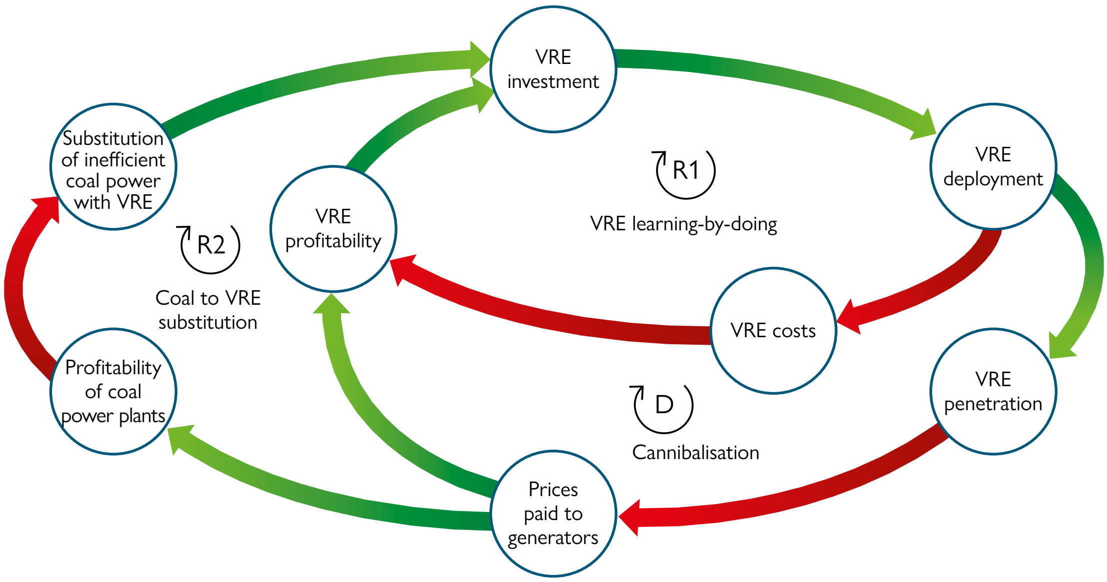


Figure 3-14: Three competing feedback loops.
Note: The innermost loop is a reinforcing loop, denoted "R1". The next outermost loop is a dampening loop, denoted "D". The very outermost loop is a reinforcing loop, denoted "R2". Green arrows indicate a positive relationship (i.e. factors move in the same direction) and red arrows indicate a negative relationship (i.e. factors move in opposite directions).

profitability of VRE projects, and in turn weakening incentives for future investment (see Chapter 1). This downwards pressure on prices can occur via market mechanisms, or via administrative adjustments to VRE pricing. The latter channel has probably dominated in China to date due to the state-set pricing regime that has traditionally apply to renewables. For example, as VRE deployment grew through the 2010s, fuelled by equipment cost declines, the NDRC reduced feed-in tariffs by up to 61% and 43% for solar and wind respectively over 2013-20 (see Table 1-1, Chapter 1) to avoid overcompensating VRE developers. The trends of market liberalisation and accelerating VRE deployment, however, threaten to strengthen this dampening feedback loop, posing a growing risk to future VRE investment (see Chapter 1).

The outermost loop of Figure 3-14, labelled R2, is a reinforcing loop that depicts inefficient coal-fired units being outcompeted by cheaper VRE, leading to a substitution in the generation mix from the former to the latter. Increased VRE deployment puts downwards pressure on power prices, as described above, which squeezes the profitability of thermal plants insofar as market arrangements allow competition between technologies. Inefficient thermal plants at the margin may be forced out of the generation mix with VRE capacity coming online to take its place, starting the cycle anew.

This feedback is potentially useful to drive the transition to a VRE-dominated system via a self-strengthening sequence of technological competition and substitution. However, some of the causal relationships that the feedback depends on may not be straightforward, or particularly strong in the Chinese context, which limits the feedback's strength.

For example, the VRE guaranteed purchase policy, price caps and floors, and the shielding of technologies from competing against one another all restrict the extent to which growing VRE penetration reduces prices and squeezes profitability of coal-fired units. Even in more liberalised systems, such as the UK's, this effect is partially muted, particularly at lower levels of VRE penetration, as prices are set by the marginal unit of supply, which is often a thermal generator, insulating these assets from price risk.

Moreover, the R2 feedback loop assumes that reduced profitability of the coal fleet causes a substitution in generation from coal to VRE. In a fully market-oriented system, less profitable assets (i.e. inefficient coal-fired units) may be retired with new investment directed to more profitable ones (i.e. cheap VRE), but this is not necessarily the case in China. Investment in and operation of the Chinese power sector still involve ad hoc administrative interventions, RPS consumption quotas, and other planning targets, leaving less scope for market forces to drive technological change in the generation mix. This is particularly true in the case of coal, which is protected as the "ballast stone"[5] of the nation's energy security.

For example, coal power capacity payments[6]—functionally a subsidy to the thermal power industry—were introduced in 2023 to shore up coal power's financial viability (see Chapter 2). The role of linked-up markets to drive technological change has therefore been constrained to date. As reforms in the sector progress, gradual market liberalisation may open the door for the emerging cost advantages of VRE over coal power to drive, or at least facilitate, this shift.

Setting aside other factors, the relative strengths of these three important feedback loops will determine whether the net feedback mechanism driven by VRE deployment is reinforcing or dampening. The learning-by-doing loop (R1) is clearly beneficial to achieving a rapid transition. A decrease in power prices driven by deployment of cheap VRE has mixed effects: it can lead to VRE cannibalisation that inhibits future deployment (loop D), but may also squeeze out inefficient thermal generators at the margin and promote the substitution of coal to clean power, where market arrangements permit (loop R2).

To accelerate the energy transition, policymakers may seek to strengthen the two reinforcing loops and attenuate the dampening one, as shown in Table 3-3.

Table 3-3: Policy options to influence feedback loops in Figure 3-14 in support of a rapid shift to a VRE-dominated system.

Objective	Policy options
Strengthen loop R1 (VRE learning-by-doing)	1. **Promote learning processes,** e.g. via knowledge spillovers, data transparency, and industry cooperation. 2. **Ensure cost declines lead to higher profitability,** e.g. by ensuring cost declines can be captured as profits, not competed away.
Weaken loop B (Cannibalisation)	1. **Weaken link between higher VRE penetration and reduced power prices,** e.g. by deploying flexible demand and energy storage to absorb VRE when prices are cheap. 2. **Neutralise the negative relationship between power prices and VRE profitability,** e.g. by providing revenue support schemes such as CfDs.
Strengthen loop R2 (Coal-to-VRE substitution)	1. **Strengthen link between power prices and coal power profitability,** e.g. by liberalising thermal power pricing and withdrawing distortive blanket coverage of coal power capacity mechanism. 2. **Allow market forces to drive technological change in generation mix,** e.g. by implementing economic dispatch.

[5] Commonly referred to as such by media, experts, and policymakers, e.g. including NEA and *People's Daily*.
[6] NDRC (2023). *Notice on establishing a coal power capacity payment mechanism.* 发改价格[2023]1501号。

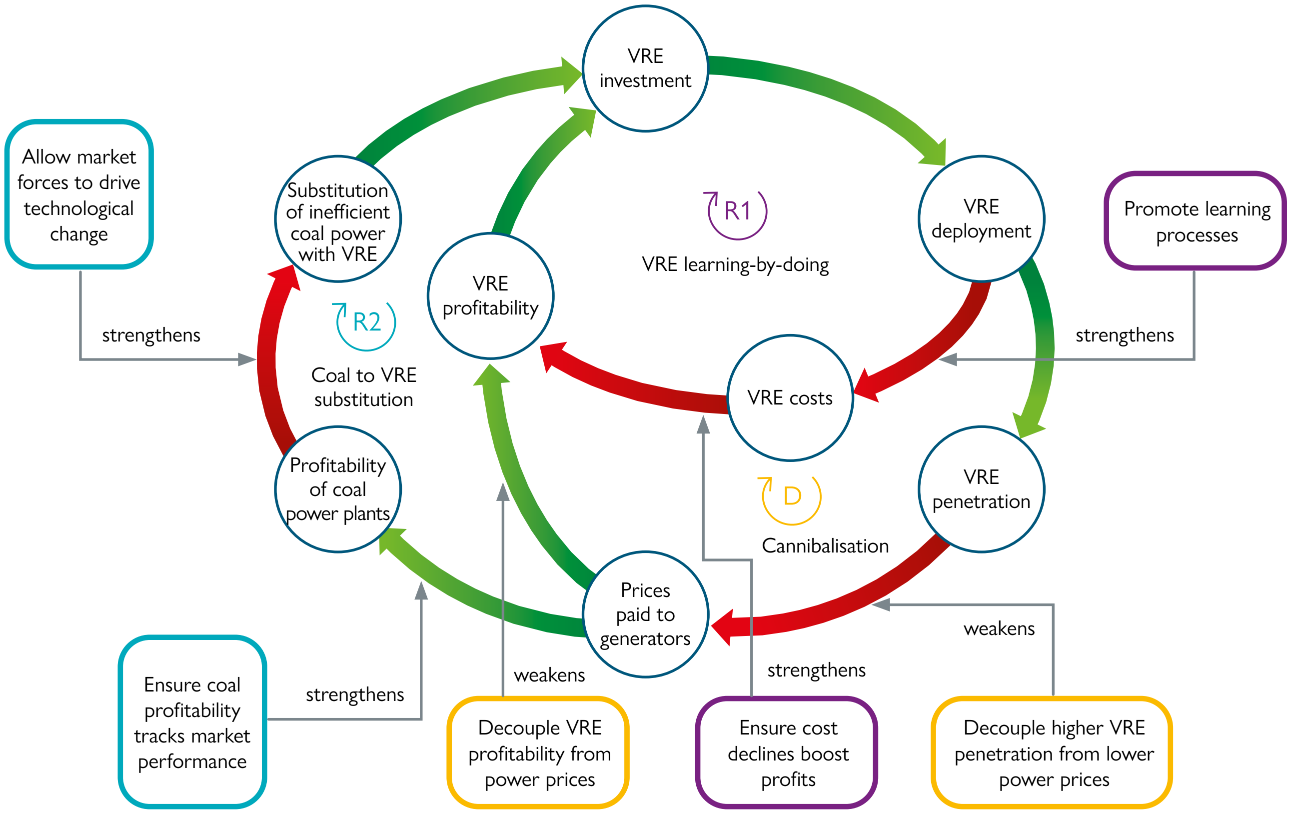


Figure 3-15: Annotated version of Figure 3-14.
Note: showing policy options from Table 3 aimed at strengthening feedback loops R1 (purple) and R2 (aqua), and weakening feedback loop D (orange). Green arrows indicate a positive relationship (i.e. factors move in the same direction) and red arrows indicate a negative relationship (i.e. factors move in opposite directions). The letters "R" and "D" denote reinforcing and dampening loops, respectively.

5. The role of price signals in feedback loops

In the preceding analysis, we have discussed feedback loops that depict causal relationships underpinned by market forces, price signals, and cost pass-through. For example, asset profitability is assumed in our diagrams to signal to investors the scale and technology of required investments in generation. Price signals are also assumed to influence operation of assets (e.g. it is assumed that spot price fluctuations increase energy storage utilisation) and electricity demand.

The heritage of China's planned economy explains the presence of many policies that dull price signals, whether intentionally or otherwise. For instance, provincial governments enforce price limits in the MLT market, allowing prices to float just 20% higher or lower than the state-set benchmark.[7] As such, accurate price signals and clear market-driven relationships cannot always be assumed.

A transition from this planned approach to a more liberalised power sector is now underway, with the current round of reforms seeking to "*…give play to the guiding role of market price signals in electricity planning and construction*"[8]. It should be noted, however, that in the Chinese context, "giv[ing] play" to market signals does not necessarily mean implementing full-blown liberalised markets as energy economists conceive of them. For example, the introduction of siloed market-oriented mechanisms with price limits may be compatible with the Chinese interpretation of "giv[ing] play" to market signals. Nevertheless, the policy trend remains oriented in the direction of liberalisation. This liberalising trend will generate a range of impacts on different

[7] See NDRC (2021). *Notice on further deepening market-oriented reforms of coal-fired power on-grid pricing.* 发改价格[2021]1439号。
[8] See NDRC and NEA (2022). *Guiding opinions on accelerating the construction of a national unified electricity market system.* 发改体改[2022]118号。

actors, geographies, and processes, as market-based incentives become increasingly important to investment in and operation of the system. It is not clear a priori whether stronger markets and price signals will accelerate decarbonisation, nor through what mechanisms these effects might play out.

For example, expansion of economic dispatch and spot markets may displace thermal power from the generation stack, but could introduce cannibalisation effects that drag on VRE development (see Chapter 1). Clearer price signals may strengthen certain feedback loops and weaken others. Our CLDs, however, do not visually acknowledge such dynamics. To interrogate these effects, we conduct a qualitative sensitivity analysis of several key feedback loops to understand how their relative strength may be influenced by liberalisation processes (see Table 3-4).

Table 3-4: Qualitative sensitivity analysis of the effects of stronger price signals on key feedback loops.

Loop	Key relationships that depend on price signals	Current strength of price signals in this loop	Effect of liberalisation on feedback	Impact on policy objectives
Learning-by-doing effects for VRE (R). Figure A-1.	An increase/decrease in VRE profitability increases/decreases VRE investment	**Moderate**. VRE investment is driven by both profitability and political factors, per interviews with industry experts.	**Mixed**. Regulators have flagged a shift to a more market-driven investment regime, strengthening this feedback. However, liberalisation may expose VRE to more competition, meaning cost reductions will not be as easily captured as profits, thus weakening it.	Uncertain. Where VRE is already profitable, liberalisation will drive further deployment. Where VRE is not profitable because it has not reached cost parity or is not well-supported by market arrangements, liberalisation may slow investment.
Learning-by-doing effects for battery energy storage systems (BESS) (R). Figure A-2.	An increase/decrease in BESS profitability increases/decreases BESS investment	**Weak**. BESS investment to date has been driven largely by the energy storage mandate rather than projected profitability of BESS assets. Market arrangements that ensure adequate economic return for BESS remain immature.	**Strengthen**. Regulators have recently annulled the energy storage mandate and have flagged a shift to a more market-driven investment regime overall.	Uncertain. Where BESS is already profitable, liberalisation will drive further deployment. Where BESS is not profitable because it has not reached cost parity or is not well-supported by market arrangements (e.g. in absence of mandate), liberalisation may slow investment.
Synergy between VRE and storage deployment (R). Figure A-3.	An increase/decrease in VRE penetration increases/decreases spot price fluctuation (peak-valley difference) An increase/decrease in spot price fluctuation (peak-valley difference) increases/decreases storage profitability	**Weak**. Spot markets generally immature or non-existent at present.	**Strengthen**. Developing spot markets with strong price signals would strengthen this loop.	Helpful. Would create a reinforcing, synergistic dynamic between storage and VRE.
Storage deployment and spot price dampening effect (D). Figure A-4.	An increase/decrease in system flexibility decreases/increases spot price fluctuation (peak-valley difference) An increase/decrease in spot price fluctuation (peak-valley difference) increases/decreases storage profitability	**Weak**. Spot markets generally immature or non-existent at present.	**Strengthen**. Developing spot markets with strong price signals would strengthen this loop.	Mostly helpful. Would provide market incentives for storage deployment when system flexibility is inadequate, but will be self-limiting if scaling up storage capacity erodes future arbitrage opportunities.
Cheap VRE promoting electrification and demand growth (R). Figure A-5.	An increase/decrease in VRE generation decreases/increases wholesale electricity prices An increase/decrease in wholesale electricity prices increases/decreases consumer power prices	**Weak**. Mechanisms to pass on the cost advantages of cheap VRE remain immature, with time-of-use tariffs being the main channel to date. Residential and agricultural users are shielded from price movements by fixed tariffs.	**Strengthen**. Allowing competition between generation technologies, pass-through of cost savings, and more liberal user pricing regimes would strengthen this loop.	Helpful. Electrification, spurred by cheaper power from VRE, is essential to meeting climate goals, and demand growth could lead to further VRE build-out.
VRE cannibalisation (D). Figure A-6.	An increase/decrease in VRE penetration decreases/increases wholesale electricity prices An increase/decrease in wholesale electricity prices increases/decreases VRE profitability	**Weak**. To date, VRE profitability has been protected by feed-in tariffs and guaranteed purchase mechanisms.	**Strengthen**. As wholesale markets grow and VRE enters market trading, cost savings of cheap VRE may be passed through to wholesale prices. Mechanisms that guarantee profitability of VRE (e.g. fixed price regimes) are being phased out.	Unhelpful. Without other support mechanisms in place (e.g. CfDs), liberalisation amid growing VRE penetration could lead to cannibalisation effects that slow deployment.

6. Conclusion

This chapter presented an exploratory analysis of the system map we developed of the Chinese power sector. Driven by discussions with and questions from policymakers and researchers, it focussed on: (i) what the map tells us about how current policy interacts with the energy trilemma; (ii) how consistent the various decarbonisation, security of supply, and market liberalisation policies are with each other; (iii) larger feedback loops that emerged from our mapping process, and (iv) the role of price signals in our analysis.

Key findings include:

- **Policy and the trilemma:** no policy in our analysis easily skirts the trade-offs between the three objectives of the energy trilemma (low costs, low emissions, and secure supply). The ETS has ambiguous impacts created by the way it affects efficient and inefficient coal in opposite directions. Other policies all involve direct trade-offs. This analysis also makes clear the central roles of coal power and market competition as mediators of the trilemma in our map.
- **Policy consistency:** there are several potential strategic inconsistencies in policies targeted at decarbonisation, market liberalisation, and security of supply. Specifically, we find that RPS targets, the new-type storage mandate, and market liberalisation have impacts on VRE profitability which push it in different directions. In addition, coal capacity payments, the ETS, and market liberalisation may potentially undermine each other with respect to their impacts on coal profitability and investment.
- **Nested feedback loops:** three interacting feedback loops around VRE and coal power extend our analysis in earlier chapters. The core learning-by-doing reinforcing feedback loop for VRE is moderated by the cannibalisation dampening loop, but potentially fortified by a third reinforcing loop involving substitution of coal power for VRE. We highlight some policy interventions which might strengthen these reinforcing feedback loops and mitigate the dampening loop.
- **The role of price signals:** we highlight the key role of price signals and market liberalisation in many of the feedback loops that we believe drive behaviour in the power sector. For each core feedback loop we assess the importance of price signals in driving feedback behaviour, and identify potential effects of liberalisation on feedbacks with respect to policy goals. We find that strengthening price signals would be helpful in achieving policy objectives by strengthening useful feedback loops related to storage deployment and electrification, but may risk triggering cannibalisation effects in the absence of VRE support mechanisms. Impacts on learning-by-doing feedbacks are likely circumstantial and depend on the stage of the transition that the system is in, relative technology costs, and the degree of policy support for key technologies.

Further work building on these findings could go in one of three directions. First, deeper analysis of specific policies or dynamics could be developed. One priority could be unpicking the complex set of impacts market liberalisation has on the power sector, both through simple causal chains and its interaction with structural feedback loops. This could be assessed using more qualitative sensitivity analysis (as we demonstrate on price signals), and/or be extended with behaviour-over time plot analysis (Kim, 1999). Quantitative assessment could employ Bayesian belief networks (focussed on conditional probabilities) or system dynamics (focussed on quantitatively modelling feedback loops).

Second, ex post evaluation methods could be used to more formally assess the policy consistency between the policies we have identified as potentially undermining each other.

Third, conceptual work could be developed out of this and other chapters in the report to comprehensively identify and describe the most important feedback loops and system archetypes relevant to power sector transitions. This will be invaluable in helping researchers and policy makers think about the transition in a more dynamic way, complementing the use of more quantitative static analyses.

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Chapter 4
The State of the Art—A review of power sector modelling in China

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Contents

1. The role of modelling in power sector policymaking

Models influence policymaking throughout the policy cycle: they support the setting of targets and the monitoring of impacts, while policymakers reciprocally shape energy modelling by defining the scope of study (Süsser et al., 2021). As such, power sector modelling is especially important for providing scientific evidence to support policy decisions. As the power industry is responsible for over 50% of China's energy-related carbon emissions, effective modelling is crucial to map out potential policies for achieving the country's carbon peak and neutrality targets (Liu et al., 2024).

Power sector models provide tools to simulate the impacts of various energy policies (e.g., carbon constraints, renewable energy development, and carbon trading) on the energy transition and economic development (Ringkjøb et al., 2018). These models are essential for understanding the complex interactions between technological change, economic growth, and policy interventions, thereby enabling policymakers to make informed decisions that align with national and global sustainability objectives (Miller-Wang et al., 2024).

2. Research questions and review methodology

Research questions and context

China's power sector has undergone significant transformations aimed at supporting rapid economic growth and meeting soaring energy demand (Guo et al., 2020). Initial reforms in the late 1990s focussed on liberalising the sector to enhance power supply capabilities. Optimisation models were used to determine the most efficient investment strategies. However, with the introduction of China's ambitious carbon peaking and neutrality targets in 2020, the policy landscape has shifted. Primary concerns now include ensuring security of supply, keeping costs affordable, and reducing emissions amid market liberalisation.

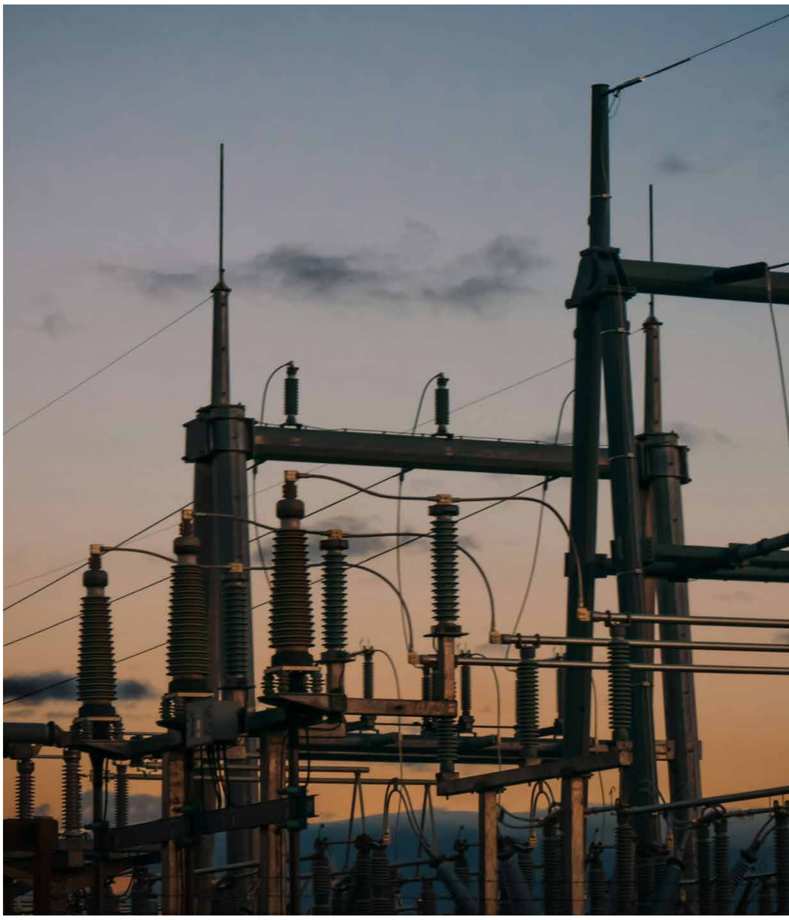
This transition has introduced complexities involving multiple government objectives and varying goals among market participants. The rapid expansion of renewable energy, particularly variable renewable energy (VRE—referring to solar PV and wind power), poses new challenges in integrating these sources into the grid while maintaining security of supply. Ongoing investment in VRE is essential for achieving China's carbon neutrality goals, yet rising penetration can reduce market value and revenues, threatening future deployment. At the same time, phasing out coal requires new forms of flexible capacity—such as energy storage—to maintain system reliability, and targeted policy support is needed to make these investments viable. Specifically, these developments raise two critical policy questions:

1. How can policy support sustain high levels of investment in VRE amid liberalisation, when rising VRE penetration threatens to erode market value and revenues (via "cannibalisation")?
2. How can policy to incentivise cost-effective deployment and use of energy storage support grid flexibility?

In a liberalised power system, addressing these questions requires models capable of capturing investment behaviour, market dynamics, policy interventions, and the technical characteristics of VRE and storage.

Review methodology

To explore these issues, we first provide a brief overview of prominent modelling approaches relevant to these questions. Then, for each of the two questions, we review a set of ten representative models, evaluating their ability to shed meaningful light on the potential effects of different policy options. To this end, we devise a list of model attributes that we deem essential, or at least desirable, to model the issue in question and potential policy responses, as shown in Table 4-1 and Table 4-2. Explanations of these attributes and the criteria we use to assess their coverage in the literature are provided in Appendix C. We then assess different models' scope, structure, policy representations, and key outputs in relation to these desirable attributes, and compare their characteristics, strengths, and weaknesses. We then discuss the usefulness of current models in relation to the policy questions and identify gaps and directions for future model development.



3. Overview of modelling methods

In China, a range of models have been adopted to address the policy questions we raised above, which can be grouped into three general types: optimisation and equilibrium models, simulation models, and integrated models.

Optimisation models and equilibrium models frame China's power sector development as a least-cost planning problem. They typically assume perfect foresight and optimal behaviour, enabling them to minimise the total discounted cost of the power system by selecting the optimal generation capacity, storage, and transmission investments over a certain planning horizon. These models enforce constraints reflecting electricity demand, reliability, and policy targets (e.g. emission caps or renewable portfolio goals). Some notable examples include:

1. TIMES-China—this model is originally derived from the MARKAL model. It captures cost reductions through endogenous learning curves based on cumulative installed capacity, an application of Wright's Law, allowing technology costs to decline as deployment increases (Q. Zhang et al., 2024).

2. SWITCH-China—this model incorporates a detailed representation of electricity markets, modelling competition between technologies, investment decisions, and system stability with high temporal resolution (hourly) and a reasonable geographic scope (e.g., provincial grids) (He et al., 2016).

3. REPO (Renewable Electricity Planning and Operation)—a new renewable energy capacity expansion and dispatch model designed specifically for the Chinese system by Tsinghua University (Yang et al., 2018; D. Zhang et al., 2024).

In general, optimisation models are suitable for analysing the impacts of policies on optimal expansion and operational planning of power system. By representing policies as system constraints (e.g. carbon emission targets, renewable energy penetration requirements) or cost modifiers (e.g. carbon taxes, capacity payments), optimisation frameworks can identify system-level cost-minimising investment and operational decisions across generation technologies and transmission infrastructure. However, a key limitation of optimisation models lies in their inability to adequately capture market dynamics.

In contrast, **simulation models** can represent market dynamics and investor behaviour without requiring an optimal solution. Investment decisions in simulation models are not outcomes of system-wide cost minimisation, but the responses of individual agents to revenue projections under specific market conditions. Therefore, simulation approaches are well-suited for analysing the impacts of policies related to market liberalisation on investment behaviours. System dynamics (SD) and agent-based modelling (ABM) are two common approaches of simulation models.

1. SD is used to model complex quantitative relationships from a top-down perspective with explicit functions between macro-level variables and is useful for studying feedback loops between variables over time (Song et al.,2021; Zhao et al., 2023; Yu et al., 2020; Huang et al., 2023). In SD models, investment in a specific generation technology is typically driven by its overall profitability, and market dynamics are primarily driven by the gap between aggregate supply and demand rather than always assuming equilibrium.

2. Unlike SD models, ABMs focus on the interactions of individual agents, such as generators, consumers, and regulators, within the power market, and are particularly suited to capturing the heterogeneous behaviours across China's power sector. For instance, ABMs can capture the differentiated responses of heterogeneous market participants—such as state-owned versus private enterprises—to policy interventions (Chen et al., 2018; Wu et al., 2020; Tan et al., 2023; Wang et al., 2023; Han et al., 2024). In ABMs, investment decisions are typically simulated at the firm level and are driven by revenue projections, making ABMs particularly effective at modelling how policy influences revenues and, in turn, investment behaviours. Market dynamics in ABMs are driven by strategic interactions among agents. However, in the context of power sector modelling, ABMs are not suited to capturing the technical nature of power system stability issues. Additionally, due to the complex nature of ABM modelling, clearly identifying explanatory factors behind the results can be challenging, and the quality of model outputs depends heavily on the assumptions, representations of agent behaviour, and data used.

In recent years, there has been a growing trend of integrating simulation models with optimisation processes (**integrated models**), which may generate new insights. These hybrid models aim to translate the traditional cost-minimising capacity expansion problem into an agent-based behavioural framework that maximises perceived revenues. They do so by simulating interactions between heterogeneous power generation agents and a grid agent under varying market and policy conditions. A representative example is the ABM–optimisation model developed by Han et al. (2024). The integration features a two-stage process: first, it models dispatch processes using an optimisation approach to determine generator outputs and spot market clearing prices; then, these prices and volumes form the basis of revenue calculations that are used in an agent-based simulation of power sector investment.

4. Policy Question I: Supporting VRE investment amid market liberalisation

Background on VRE development in China

Spurred by the 2005 *Renewable Energy Law* and its 2009 amendment (Ministry of Ecology and Environment, 2009), China has implemented feed-in tariffs via fixed-price purchase guarantees for renewable energy (Ministry of Commerce PRC, 2013). This framework has provided robust support for the growth of renewable energy in China, but the fiscal cost of these policies has been substantial: between 2012 and 2020, the central government allocated over CNY450 billion in subsidies to support renewable energy development (The State Council, PRC, 2020).

In 2021, the central government ended subsidy schemes for solar PV and onshore wind, as they had become cost-competitive with coal-fired electricity. By 2024, installed wind and solar capacity reached 1,408 GW, representing 42% of total capacity (Climate Energy Finance, 2023). This rapid expansion enabled China to meet its 2030 renewable energy deployment target (1200 GW) six years early. In February 2025, NDRC and NEA issued *Document 136—or Notice on deepening market-oriented reform of new energy on-grid prices and promoting the high-quality development of new energy*. This policy mandates that all electricity generated by new renewable energy projects participate in market transactions to determine on-grid tariffs. To ensure revenue stability and investment attractiveness, it also establishes a "price settlement mechanism for the sustainable development of new energy", which bears some similarities to investment-supportive CfDs (see Chapter 1).

However, the attractiveness of renewable investments under liberalised markets remains uncertain. As VRE penetration increases, price cannibalisation may occur, where generators earn lower prices during peak output periods, threatening profitability. A notable example is the occurrence of negative electricity prices in Shandong for 22 consecutive hours during the May 2023 national holidays, driven by excess generation from coal and renewables (S&P Global, 2023). While several studies have examined cannibalisation effects of renewable energy (López Prol et al., 2020; Peña et al., 2022), understanding this issue and potential policy responses requires modelling the interaction between policy incentives, investment decisions, and market price dynamics. Yet, financial factors are often underrepresented in existing models. Here, we review relevant literature and present Table 4-1, which summarises the attributes of selected models used to analyse policy scenarios relevant to VRE investment in liberalising markets.

Model review analysis

As mentioned in Section 2, we assess the design of 14 prominent power sector models against a set of attributes that we believe are necessary or desirable to meaningfully model this policy challenge. Criteria for the selection of models to be reviewed included having VRE installed capacity as an output, as well as aiming to incorporate other relevant outputs such as the capacity mix, generation mix, and thermal power generation/carbon emissions where possible.

In the following subsections, we discuss our assessment of the selected models in terms of the models' scope, structures, and modelled policy options.

Scope of models

Our review focuses on model characteristics related to revenue uncertainty, since this strongly influences investor confidence and financing decisions. Capturing market competition, bidding strategies, and market design is therefore essential to reflect the key dynamics affecting profitability. As shown in Table 4-1, among selected models, simulation approaches commonly model the bidding strategies and investment behaviours of power sector firms, offering a more nuanced representation of market participants' response to VRE incentive policies, while optimisation models generally fail in this aspect. Models of both styles incorporate dynamic technology costs, but only simulation models represent endogenous technology progress.

Modelling technical constraints that preserve system stability is essential to ensure realistic dispatch scenarios. Inspection of Table 4-1 and our selected modelling studies reveals that compared to simulation models, optimisation models more frequently incorporate these constraints and have higher spatial and temporal resolution, thereby supporting more realistic forecasts of power system operation with high penetration of VRE. As such, it is unclear whether the results of the reviewed simulation models are entirely realistic from a system operation perspective, as maintaining system stability is a large, and growing, challenge in the context of growing VRE penetration.

However, despite their advantages in terms of modelling technical constraints, optimisation models lack explicit representation of market mechanisms—such as bidding strategies, financing, and investment decisions. Without explicitly modelling individual investor profits or financial returns, optimisation models may produce results that do not reflect profit-driven investment behaviours at the firm or investor level. Consequently, policy mechanisms that enhance bankability, such as feed-in tariffs or CfDs, cannot be modelled as endogenous drivers of investment behaviour. Additionally, price volatility and uncertainty are difficult to model with optimisation approaches: these models usually operate in a deterministic fashion with perfect foresight, meaning they don't capture the risk premium investors might demand in a liberalised market with volatile prices.

Structure of models

In terms of model structure, high temporal resolution is deemed desirable because intraday and seasonal variations in VRE output significantly affect revenue streams. As spot markets develop in China, rising VRE penetration will tend to depress market prices during periods of high VRE output. Consequently, a fine temporal resolution, with some representation of intra-day fluctuations, is likely to be important for simulating the cannibalisation problem and testing policy measures that aim to address it. To accurately model investor behaviour, we assess whether models address heterogeneous investor preferences and use an appropriate investment horizon.

As shown in Table 4-1, optimisation-based operational models typically feature high temporal and spatial resolutions, often operating on an hourly basis and at the provincial level. Some models even aggregate renewable resources across even smaller scales (e.g. tens of kilometres) (Zhu et al., 2025). This high level of granularity enables more detailed and accurate forecasts of power system operations. In contrast, simulation models generally adopt annual time steps and represent a single region, making their forecasts more indicative of long-term trends rather than short-term system dynamics. We also find that only ABMs model heterogeneous investor behaviours, which is not surprising.

Policy options modelled

The primary objective of this review is to evaluate the extent to which existing models are capable of modelling different policy options and their effects. We assess whether the 14 selected modelling studies test certain policy options that we deem relevant to VRE development. From this perspective, policy tools aimed at promoting VRE investment can be broadly categorised into three groups.

The first category of policies shown in Table 4-1 includes those related to targets or regulatory requirements. We include rows in the table dedicated to the major policies: renewables portfolio standards (RPS) and carbon emissions targets. Where models test other policies of a similar nature, such as adequacy requirements, flexibility constraints, and development strategies for low-carbon power technologies, we acknowledge this with an "R" (for regulatory policy) in the row *Other policy settings*. As shown in Table 4-1, all selected optimisation models incorporate carbon targets as constraints. Simulation models also incorporate carbon targets, but this is generally modelled as a modified ETS.

The second category of policies shown in Table 4-1 includes those related to market-oriented mechanisms and price reforms. We include rows in the table dedicated to the green electricity certificates (GEC) scheme, investment CfDs, and the emissions trading scheme (ETS). Where models test other policies of a similar nature, such as spot market development, demand response incentives, and financing mechanisms, we acknowledge this with an "M" (for markets) in the row *Other policy settings*.

The third category of policies includes financial transfers. This category includes policies such as such as investment subsidies for VRE projects and fixed carbon taxes. Due to their relatively scant coverage in our selected models, we do not include any rows dedicated to these specific policies in Table 4-1, and instead enter an "F" (for financial transfers) in the row *Other policy settings* when one (or more) of these policies is tested in a modelling study. We note that although modelling carbon taxes is relatively straightforward in both optimisation and simulation approaches, few of our selected models do so.

Table 4-1: Comparison of different attributes of models that are used to model VRE development.
Note: The list of model features on the left represents a selection of attributes that we believe are desirable and/or useful in the context of modelling VRE development. Explanations of these attributes and the criteria we use to assess their coverage in the literature are provided in Appendix C. A "Y" in a cell indicates that a model includes a certain attribute, an "N" represents that it does not. In the row "Dynamic technology costs", "Y-en" indicates that technology progress is modelled endogenously. The letters "R", "M", and "F" in the row "Other policy settings" indicate that the model tests some policy that is not already listed in the table—"R" is for regulatory policies, "M" is for market-oriented policies, and "F" is for financial transfer policies.

Model	**Methodology**	**Optimisation/Equilibrium Model**						**Simulation**						**Integrated Model**	
	Model Name	CISPO	REPO	SWITCH-China	TIMES-30PE	LEAP-REP	GCAM	SD			ABM			ABM-Optimisation	SD-LEAP
	References	Zhu et al, 2025	Zhang et al., 2023	He et al, 2020	Zhang et al, 2024	Ren et al, 2024	Pan et al., 2023	Song et al., 2021	Zhao et al, 2023	Yu et al, 2020	Sharpe et al., 2023	Chen et al, 2018	Tan et al, 2023	Han et al, 2024	Wu et al, 2024
Scope	Competition in the electricity market	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y
	Different sales channels	N	N	N	N	N	N	Y	Y	N	N	N	Y	Y	Y
	Power market bidding strategies	N	N	N	N	N	Y	N	N	N	N	Y	Y	Y	N
	Financing of investments	N	N	N	N	N	N	N	N	Y	Y	Y	Y	Y	N
	Investment decisions	N	N	N	N	N	N	N	N	Y	Y	Y	Y	Y	Y
	All generation technologies	Y	Y	Y	Y	Y	Y	N	Y	Y	Y	Y	Y	Y	Y
	Dynamic technology costs	Y	Y	Y	Y	Y	Y	N	Y-en	Y-en	Y	Y-en	Y	Y	Y-en
	System stability	Y	Y	Y	Y	Y	N	N	N	N	N	N	N	Y	N
Structure	Temporal resolution	hour	hour	hour	hour	hour	year	month	year	year	year	year	year	15min	year
	Investment decision intervals	10-year	5-year	5-year	5-year	5-year	yearly	monthly	yearly	yearly	yearly	yearly	yearly	yearly	yearly
	Geographical representation	25×25km	provincial	provincial	provincial	national	national	national	national	firm	national	national	provincial	provincial	national
	Heterogeneous decision making	N	N	N	N	N	N	N	N	N	Y	Y	Y	Y	N
Policy options	Business-as-usual scenario	Y	Y	Y	Y	Y	Y	Y	Y	N	Y	N	N	N	Y
	RPS	N	N	N	N	N	N	Y	Y	N	N	N	N	N	N
	Carbon target	Y	Y	Y	Y	Y	Y	N	Y	Y	Y	Y	Y	Y	N
	Green electricity certificates	N	N	N	N	N	N	Y	Y	N	N	N	N	N	N
	Investment CfDs	N	N	N	N	N	N	N	N	N	N	N	N	N	N
	ETS	N	Y	N	N	N	Y	N	Y	N	Y	Y	Y	N	Y
	Other policy settings	N	N	N	N	F	R	M	M	F	F	N	M	M, F	R
Outputs	VRE installed capacity	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y
	Installed capacity mix	Y	Y	Y	Y	Y	Y	N	Y	Y	Y	Y	Y	Y	Y
	Generation mix	Y	Y	Y	Y	Y	N	N	Y	Y	Y	Y	N	Y	Y
	Thermal generation or emissions	Y	Y	Y	Y	Y	Y	N	Y	Y	Y	Y	Y	Y	Y

5. Policy Question II: Incentivising cost-effective energy storage deployment

Background on energy storage development in China

China's push for carbon neutrality has spurred rapid growth in energy storage deployment to integrate VRE. The government's ambitious VRE deployment targets are accompanied by policies encouraging storage adoption (J. Zhang et al., 2023). For example, a national mandate requiring new renewable plants to include battery storage (typically 15% of plant capacity with 4 hours duration) was introduced to enhance grid flexibility—though this policy was abolished in February 2025. However, studies show such mandates can significantly raise costs for VRE investments—by roughly 15% for wind and 21% for solar PV on average (J. Zhang et al., 2023)—which was part of the logic behind this policy's annulment. The question therefore remains as to what new policies, if any, will drive storage deployment in a post-mandate era. Possibilities include capital subsidies, spot market development, time-of-use tariffs, ancillary service markets for storage (e.g. frequency regulation), and allowing new business models (shared or third-party storage), among others. Modelling the effects of these policies requires capturing both long-term investment trade-offs (storage vs. other resources) and short-term operational value streams (arbitrage, ancillary services, etc.), as well as the impact of policy incentives on the profitability of storage assets.

Table 4-2 summarises 12 representative models that address energy storage deployment and usage, again covering different modelling approaches. To thoroughly investigate policy effects on storage adoption, we determine that the model **outputs** should emphasise investment decisions and deployment outcomes for energy storage, potentially including features such as flexible low-carbon installed capacity and relevant stability metrics. Regarding the model's **scope**, key market dynamics—particularly real-time electricity pricing—are essential, as these affect investor strategies, operational decisions, and potential revenues. Evaluating the different revenue streams available to storage assets—such as arbitrage, ancillary services, and capacity payments—is crucial, given that investors, particularly from the private sector, are sensitive to variation in revenue projections when assessing projects. Modelling technology costs as a function of learning-by-doing effects, either endogenously or via some other dynamic mechanism, is deemed key to capturing realistic technology cost profiles. Additionally, explicitly modelling investment decision-making and financing structures responsive to revenue projections is necessary for realistically depicting how private investors respond to different policy options.

In terms of model **structure**, we assess the temporal resolution and geographical scope of the selected models; the former is important as fine-scale temporal resolution may capture short-term supply, demand, and price movements that affect storage, while the latter is important as modelling an area that is too large (e.g. a continent) or small (e.g. a city) may produce misleading results. We also assess the decision-making processes (e.g. regarding investment, plant shut-down, etc.) built into selected models, as investors have diverse risk profiles and objectives that influence their responses to market signals and policy interventions.

Model review analysis

Prevalence of optimisation models

Our search of the literature revealed that optimisation models are more common in the literature on energy storage development (see Table 4-2); notable examples include CISPO, SWITCH-China, REPO, TIMES-30PE, and GTEP. Their dominance may be due to the technical characteristics of energy storage. Energy storage technologies are essential for maintaining power system balance, which is closely tied to grid operations. Ensuring grid stability is a centralised operational planning task that is inherently a dynamic optimisation problem, making optimisation methods indispensable. Furthermore, modelling the role of energy storage in grid balancing requires a finer temporal resolution, often at an hourly or even minute-level scale. Therefore, power system planning models with higher temporal resolution and higher spatial accuracy (at the provincial or grid level) can more accurately reflect the value of energy storage in real-world power systems.

Simulation approaches to energy storage development are relatively rare, and their outputs are generally more concerned with market-related variables such as prices and trading volumes, rather than the installed capacity of energy storage. Among the models we initially screened, very few SD models examine energy storage deployment. This may be due to the top-down nature of SD models, which makes them better suited for capturing interactions between macro-level variables. Additionally, SD models typically operate on a coarser time scale (often annual), making it challenging for them to accurately capture the operational nuances and development pathways of energy storage systems.

Policy options modelled

We define three categories of policies that support energy storage development: 1) regulatory policies; 2) market-oriented policies; and 3) financial support policies. In Table 4-2, we review the coverage of these policies among 12 prominent power sector modelling studies that focus on energy storage.

For category (1)—regulatory policies—we take this to include interprovincial connections (insofar as the level of interprovincial connection and trading is largely set by governments, not markets), and the energy storage mandate for VRE developers (including energy storage connection strategies) in Table 4-2. Models that cover other, less commonly-modelled regulatory policies (e.g. long-duration energy storage deployment, adequacy requirements, flexibility constraints, and adjustments to balancing areas) are marked with an "R" (for regulatory) in the Table 4-2 row *Other policy settings*. For regulatory policies and requirements, optimisation models are perhaps better suited to modelling their implementation, whereas simulation models are less capable. For example, battery storage deployment strategies (grid-side, generator-side, or demand-side) can be implemented in the structure of the power system in SWITCH-China (Peng et al., 2023). Additionally, designs for balancing areas (provincial, regional, or national) (Lin et al., 2022) and capacity adequacy requirements are easily modelled through imposing operational constraints on optimisation models (Yin et al., 2021).

For category (2)—market-oriented policies—we take this to include capacity markets and spot market liberalisation in Table 4-2. Models that cover other, less commonly-modelled market-oriented policies (e.g. different spot market designs, demand response, ancillary service markets, and spot market participation) are marked with an "M" (for market) in the Table 4-2 row *Other policy settings*. Not a single optimisation model that we reviewed modelled these policies (barring Liang et al., 2024), whereas both simulation models and the one integrated model reviewed all do. These models can represent investor behaviour and spot market bidding strategies, and are therefore useful in simulating market-oriented policies, such as spot market development (Wu et al., 2020) or capacity auctions (Huang et al., 2023). Despite their aptitude for modelling market processes, ABM applications in energy storage research have mainly focussed on short-term pricing and balancing dynamics, with limited attention given to linking spot market behaviour to long-term investment trends.

For category (3)—financial transfer policies—we take this to include capacity payments in Table 4-2. Models that cover other financial transfer policies that are less commonly covered in the energy storage literature (e.g. investment subsidies and carbon taxes) are marked with an "F" (for financial support) in the Table 4-2 row *Other policy settings*. As shown in Table 4-2, optimisation models frequently model these policies—they can do so relatively simply by incorporating financial transfers into the cost component of the objective function. Simulation models, theoretically speaking, could also achieve this by incorporating financial transfers into cost- or revenue-related functions, but neither of the two models we reviewed did so.

A hybrid approach that combines optimisation and simulation methods could be a promising pathway for integrating power system operational planning with market dynamics. One such example is Han et al. (2024), who integrated an investment-focussed ABM with optimisation techniques to investigate how different policy measures, such as subsidies or capacity compensation, can encourage the diffusion of low-carbon technologies amid spot market expansion. This hybrid approach captures both the real-world operational role of storage systems and the long-term impact of incentive policies on storage investment behaviour over multi-year horizons. However, Han et al. (2024) did not explicitly simulate capacity market auctions or include technical system stability metrics (such as ramp rates or frequency stability), areas that future integrated ABM-optimisation models could explore further.

Table 4-2: Comparison of different attributes of models that are used to model energy storage development. Note: The list of model features on the left represents a selection of attributes that we believe are desirable and/or useful in the context of modelling energy storage development. Explanations of these attributes and the criteria we use to assess their coverage in the literature are provided in Appendix C. A “Y” in a cell indicates that a model includes a certain attribute, an “N” represents that it does not. The letters “R”, “M”, and “F” in the row “Other policy settings” indicate that the model tests some policy that is not already listed in the table—“R” is for regulatory policies, “M” is for market-oriented policies, and “F” is for financial transfer policies.

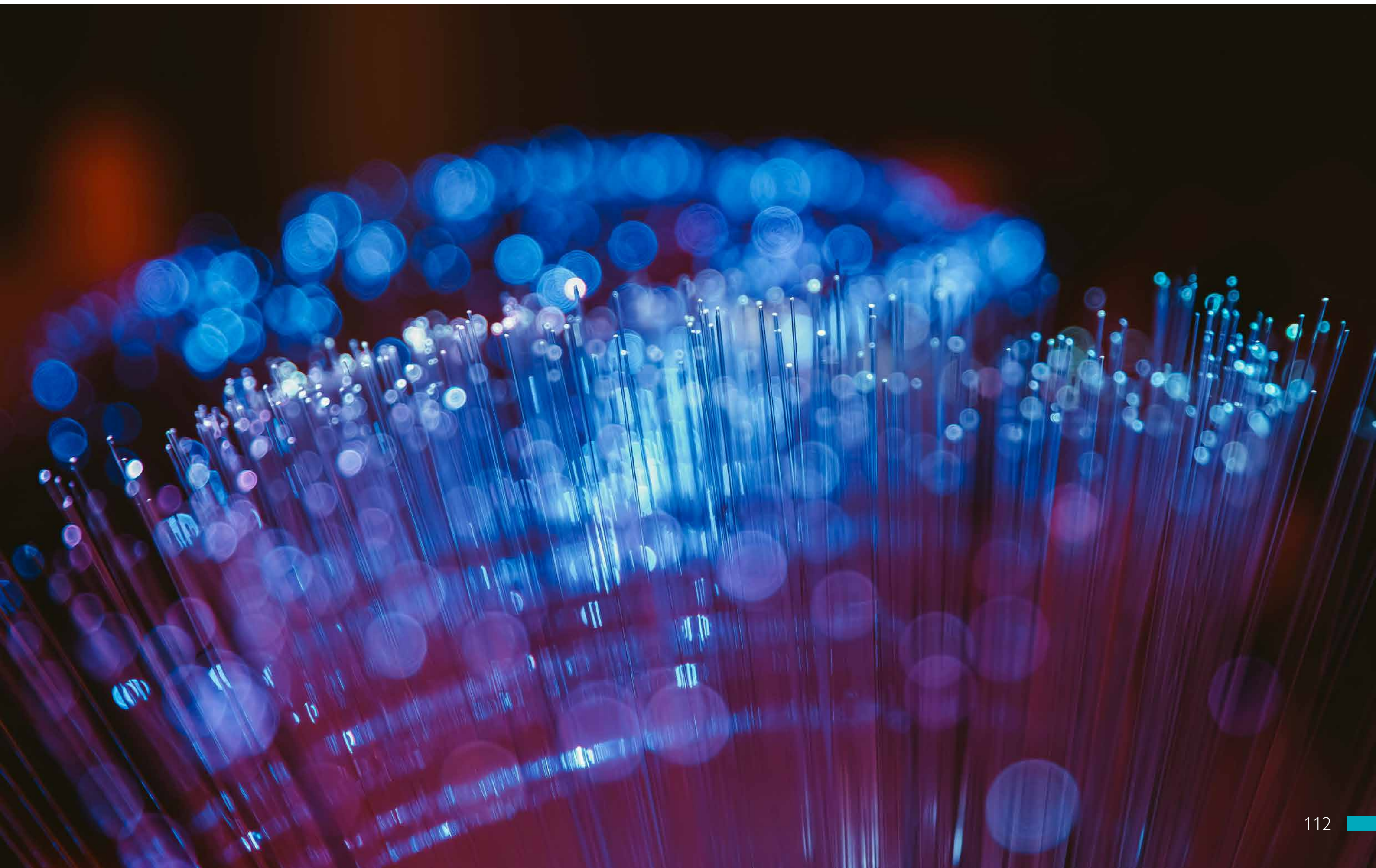
Model	Methodology	Optimisation									Simulation		Simulation+ Optimisation
	Model type	CISPO	REPO	SWITCH-China			SWITCH-China +PLEXOS	TIMES-30PE	GTEP	Other	SD	ABM	ABM+Optimisation
	References	Zhu et al, 2025	Liang et al., 2024	Zeng et al., 2024	Peng et al., 2023	Yin et al., 2021	Lin et al., 2022	Zhang et al., 2024	Zhuo et al., 2022	Chen et al., 2021	Huang et al., 2023	Wu et al.,2020	Han et al., 2024
Scope	Electricity spot market (or time-differentiated tariffs)	N	N	N	N	N	N	N	N	N	Y	Y	Y
	Ancillary services market	N	Y	N	N	N	N	N	N	N	Y	N	N
	Different revenue channels for storage	Y	N	N	N	N	N	Y	N	Y	N	N	N
	Financing of investments	N	N	N	N	N	N	N	N	N	N	N	Y
	Investment decisions	N	N	N	N	N	N	N	N	N	Y	N	Y
	Multiple storage technologies	Y	Y	Y	Y	Y	Y	Y	Y	Y	N	N	N
	Dynamic technology costs	Y	Y	Y	Y	Y	Y	Y	Y	Y	N	N	Y
	System stability	Y	Y	Y	Y	Y	Y	Y	Y	Y	N	N	Y
Structure	Temporal resolution	hour	hour	hour	hour	hour	hour	hour	hour	hour	year	5 min	15 min
	Investment decision intervals	10-year	5-year	5-year	5-year	5-year	5-year	5-year	5-year	10-year	yearly	Null	yearly
	Geographical representation	25×25km	provincial	provincial	provincial	regional	provincial	provincial	9×9km	provincial	national	national	a province
	Heterogeneous decision making	N	N	N	N	N	N	N	N	N	N	Y	Y
Policy options	No dedicated security/flexibility policies	Y	Y	Y	Y	N	Y	N	Y	N	N	N	Y
	Capacity payments	Y	Y	N	N	Y	N	Y	Y	N	N	N	Y
	Energy storage mandate	N	N	N	Y	N	N	N	N	N	N	N	Y
	Interprovincial trade	Y	Y	Y	Y	Y	Y	Y	Y	Y	N	N	N
	Capacity market auctions	N	N	N	N	N	N	N	N	N	Y	N	N
	Spot market liberalisation	N	N	N	N	N	N	N	N	N	Y	Y	Y
	Other policy settings	R	M	R	F	R	R	N	N	R	M	M	F
Outputs	BESS installed capacity	Y	Y	Y	Y	Y	Y	Y	Y	Y	N	N	Y
	Flexible, low-carbon installed capacity	Y	Y	Y	Y	Y	Y	Y	Y	Y	N	N	Y
	Installed capacity mix	Y	Y	Y	Y	Y	Y	Y	Y	Y	N	N	Y
	Generation mix	Y	Y	Y	Y	Y	Y	Y	Y	Y	N	N	Y
	Contribution to stability metrics	Y	Y	Y	Y	N	Y	N	Y	Y	N	Y	Y

6. Recommendations for future model development

The literature on Chinese power sector modelling of VRE investment and energy storage deployment exhibits key gaps.

Optimisation models typically assume perfect foresight and centralised decision-making, omitting consideration of factors such as uncertainty, market dynamics, and investor behaviour. Simulation models, including SD and ABM, offer better representations of market behaviour but often neglect technical constraints and temporal resolution. Hybrid approaches that integrate simulation with optimisation methods demonstrate considerable potential by combining decentralised investment behaviour modelling with optimised system operations.

Building on these advances, future power sector modelling work in China should aim to incorporate investment-relevant financial factors—such as revenue uncertainty, cost of capital, and heterogeneous investor preferences—into optimisation frameworks. While ABMs emerged from the model review as the most effective for capturing investor behaviour, their policy relevance is contingent on the quality of input data and the appropriateness of parameter assumptions. Greater effort is needed to develop ABMs that explicitly represent firm-level investment strategies, market bidding behaviour, and responses to dynamic policy instruments. Ultimately, integrated modelling approaches that combine the strengths of both optimisation and simulation are essential. These could feature enhanced spatio-temporal granularity, simulations of financial and market uncertainties, and the flexibility to incorporate emerging market designs such as peer-to-peer trading or shared storage investment models. Advancing these capabilities will produce more robust, policy-relevant insights to support China's energy transition and help balance the competing objectives of reliability, cost-effectiveness, and decarbonisation.



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Annex A:

Feedback loop diagrams from Table 3-4, Chapter 3

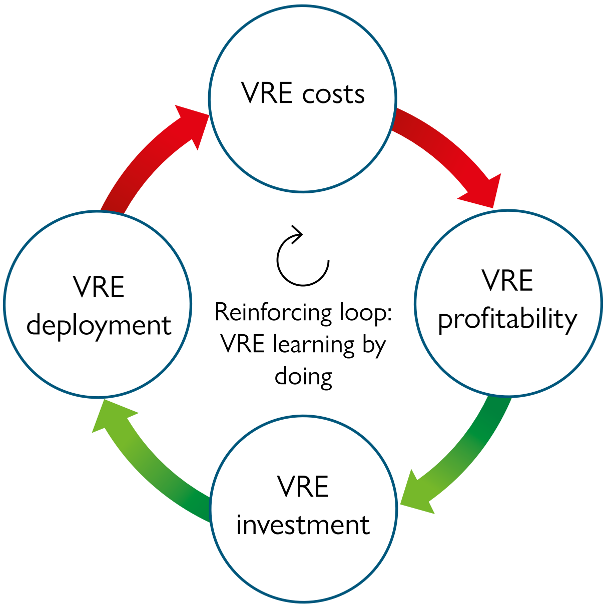


Figure A-1: CLD of learning-by-doing effects for VRE.
Note: Green arrows represent positive relationships (i.e. variables move in the same direction), and red arrows represent negative relationships (i.e. variables move in opposite directions).

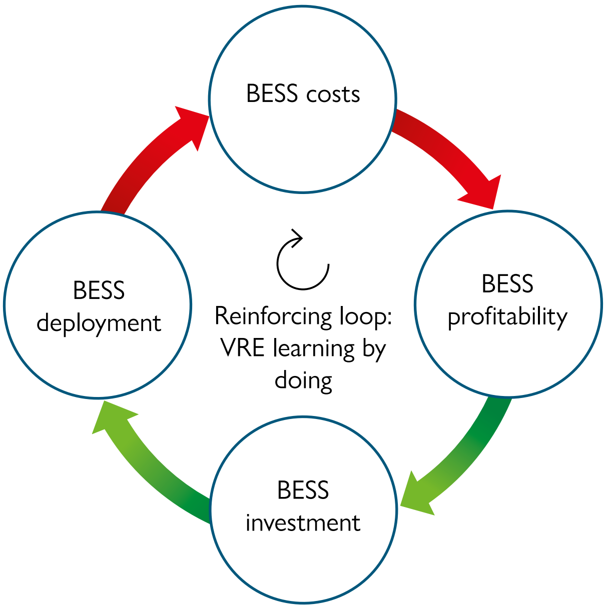


Figure A-2: CLD of learning-by-doing effects for BESS.
Note: Green arrows represent positive relationships (i.e. variables move in the same direction), and red arrows represent negative relationships (i.e. variables move in opposite directions).

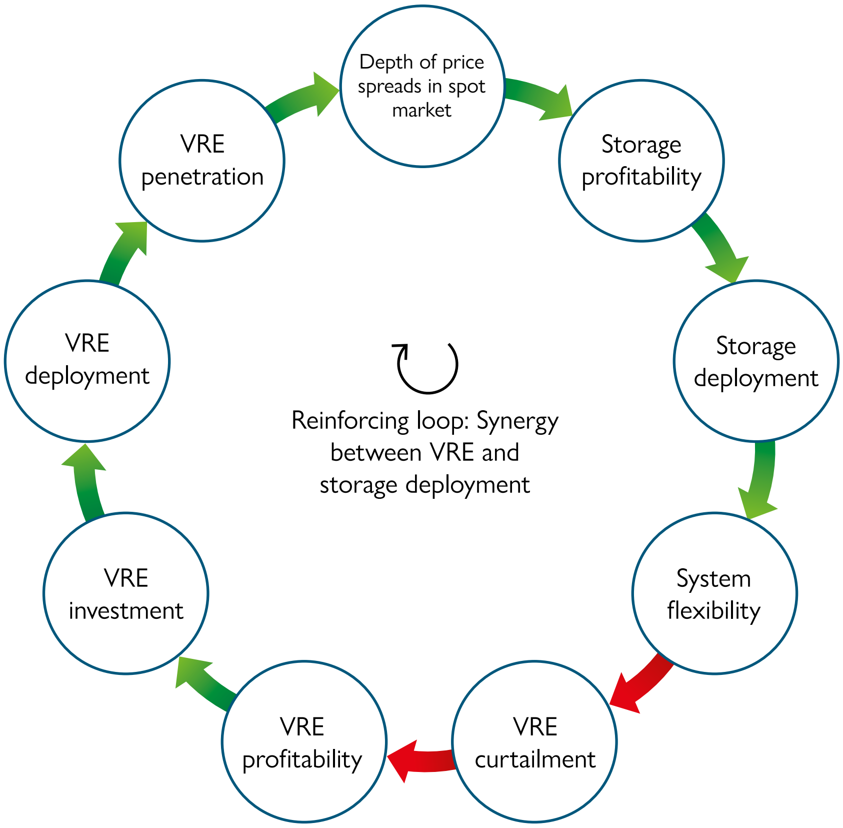


Figure A-3: CLD of synergy effects between VRE deployment and storage deployment.
Note: Green arrows represent positive relationships (i.e. variables move in the same direction), and red arrows represent negative relationships (i.e. variables move in opposite directions).

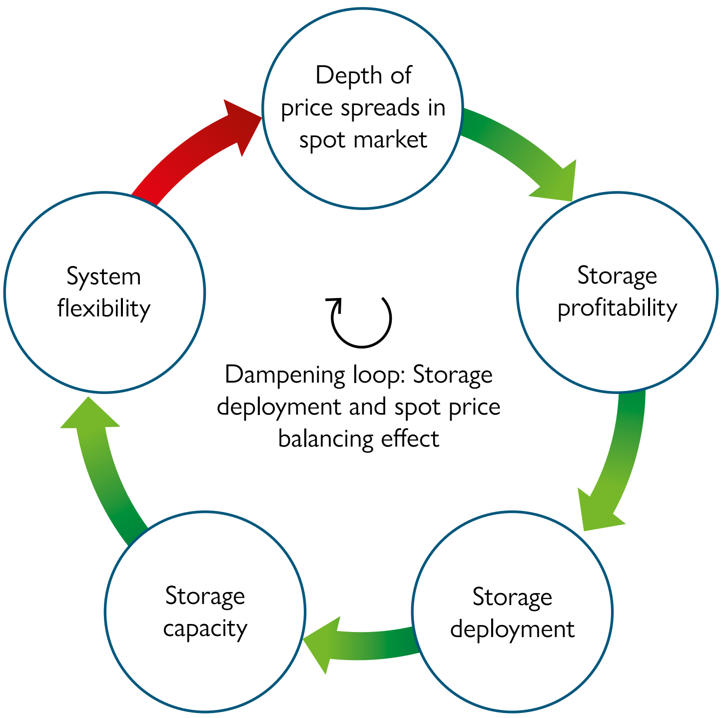


Figure A-4: CLD of spot price and storage arbitrage interactions.
Note: Green arrows represent positive relationships (i.e. variables move in the same direction), and red arrows represent negative relationships (i.e. variables move in opposite directions).

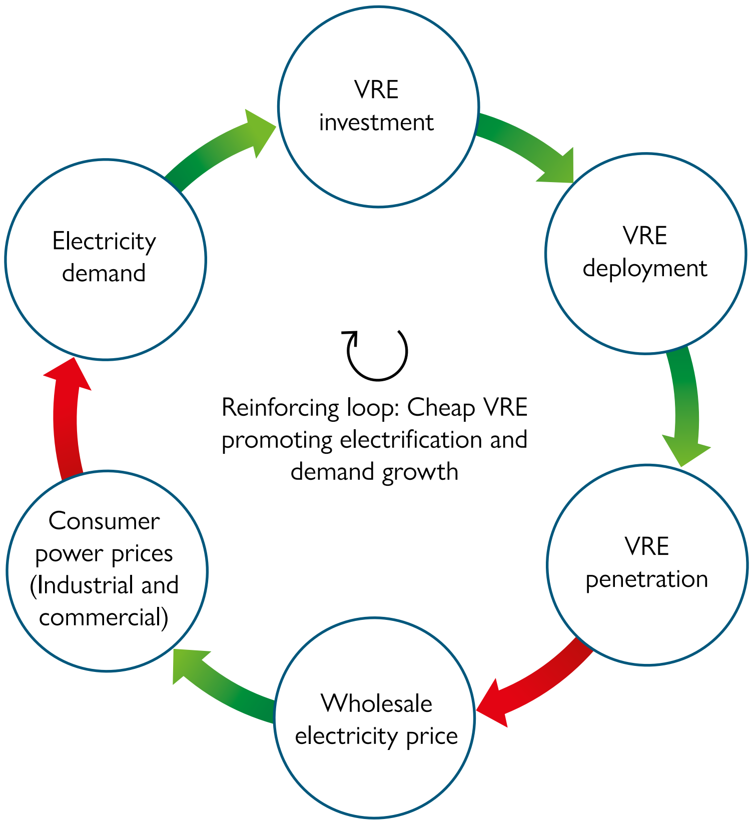


Figure A-5: CLD of cheap VRE promoting electrification and demand growth, triggering more VRE investment.
Note: Green arrows represent positive relationships (i.e. variables move in the same direction), and red arrows represent negative relationships (i.e. variables move in opposite directions).

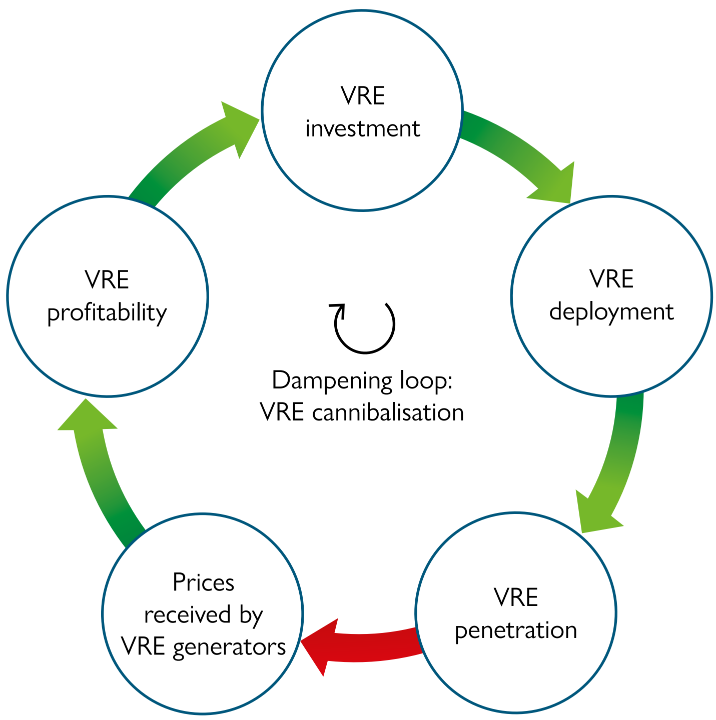


Figure A-6: CLD of cannibalisation effects on VRE.
Note: Green arrows represent positive relationships (i.e. variables move in the same direction), and red arrows represent negative relationships (i.e. variables move in opposite directions).

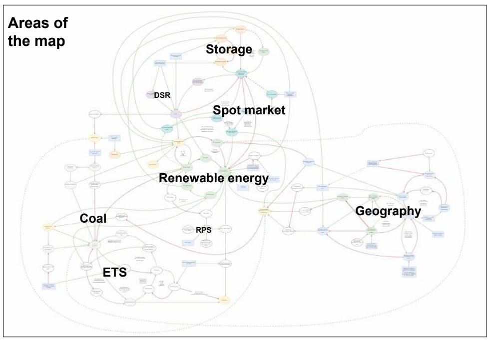
Annex B:

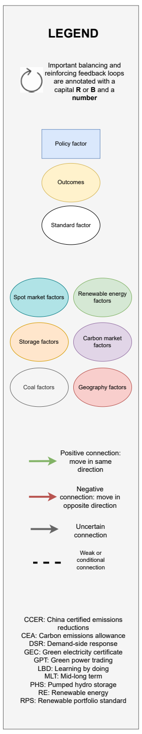
Overall systems map

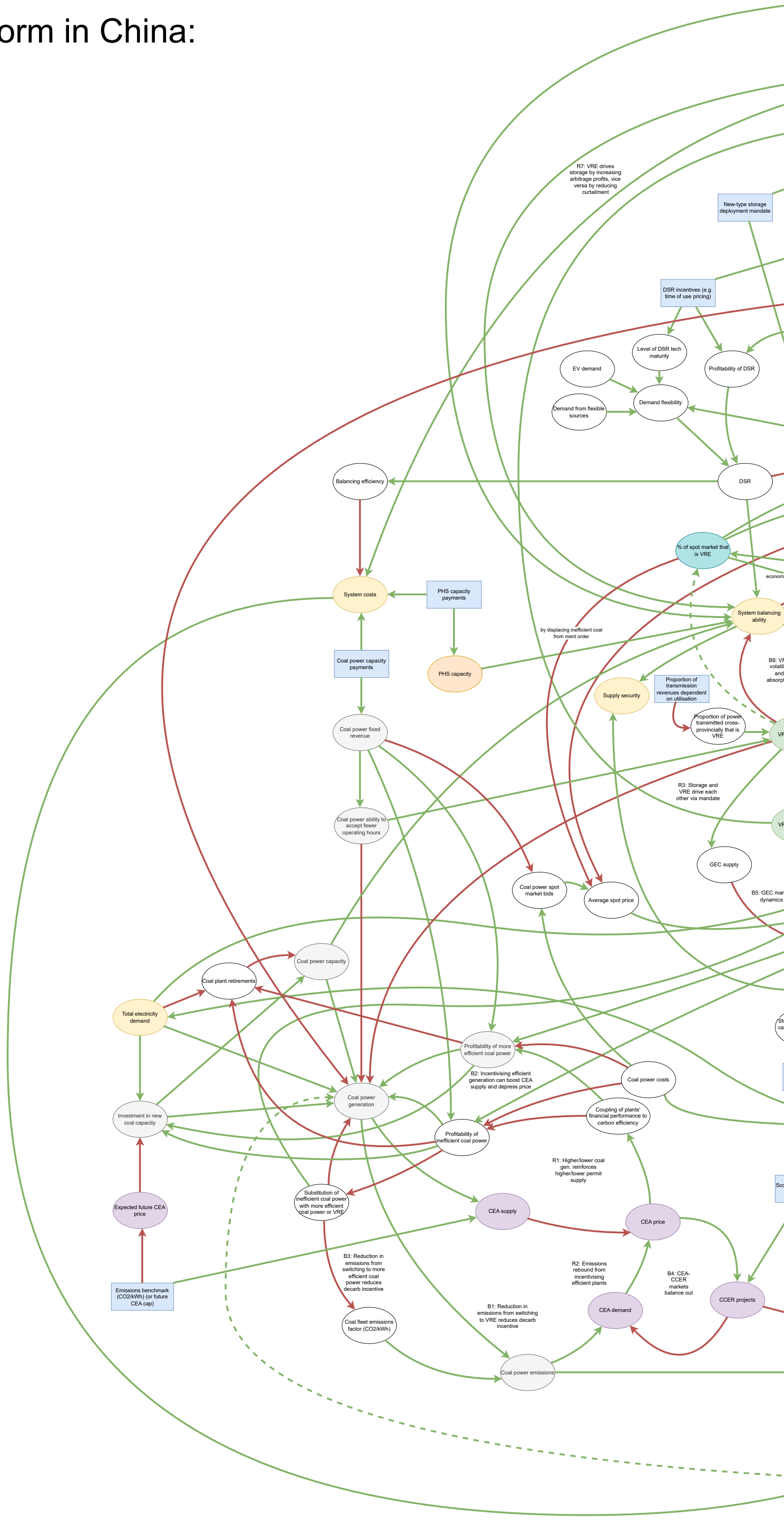
Systems mapping of power sector reform in China: **Overall map**

What is this? This diagram is a large causal loop diagram, a type of system map, which was created with researchers and policy analysts in China and the UK. It shows some of the causal influences between important factors in Chinese power sector reform. It was built based on four smaller maps focussed on (i) decarbonisation policies, (ii) system balancing policies; (iii) market efficiency policies; and (iv) geographical dynamics.

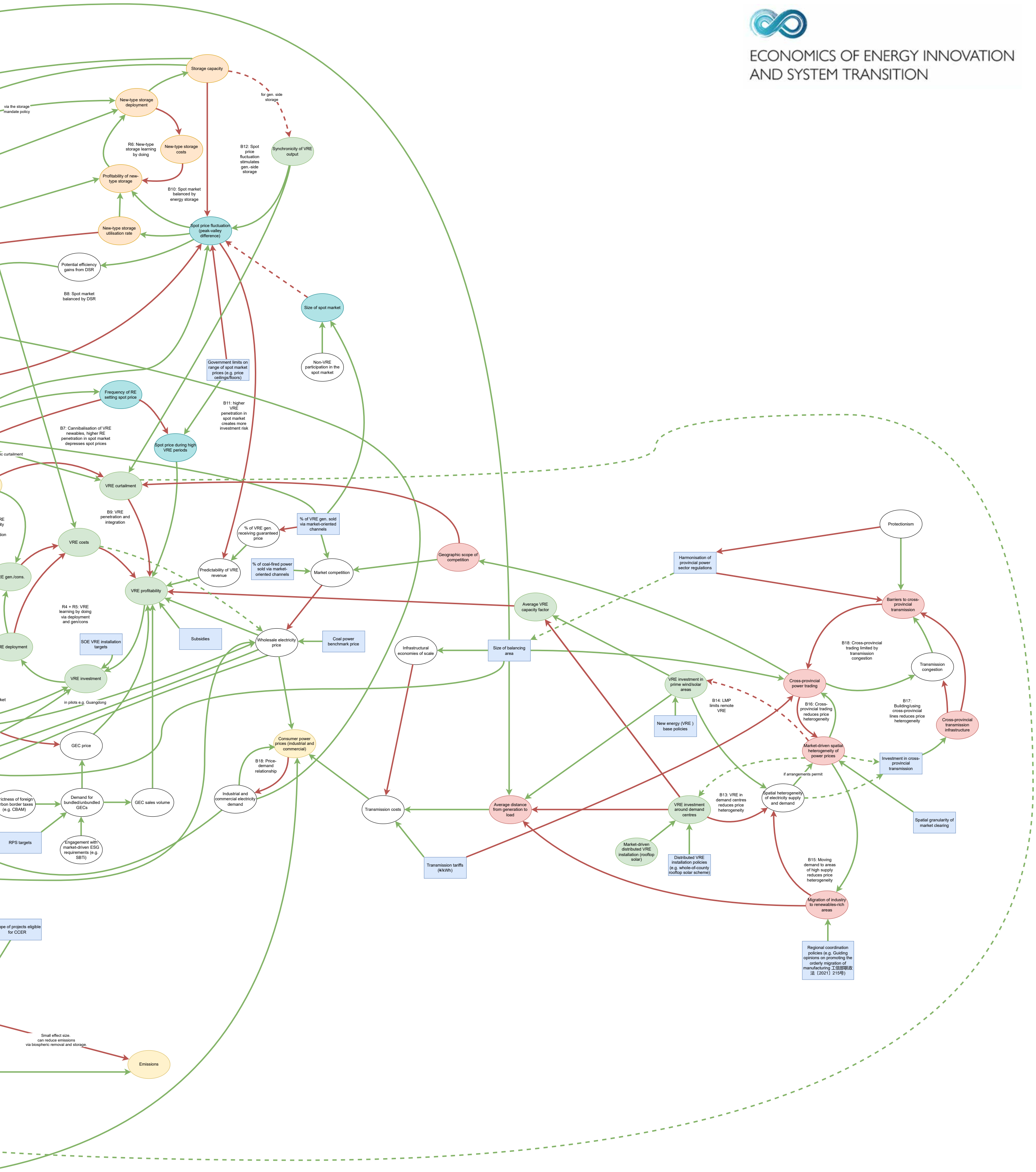
How do you read this map? The map is large and can be overwhelming. The best ways to start reading this diagram is either: (i) pick one of the broad areas shown below in the small version of the map and start there; (ii) focus on the causal loops depicted with circular arrows, and consider how these drive system behaviour, or (ii) find a policy you are interested in and explore how it affects the system.







ECONOMICS OF ENERGY INNOVATION AND SYSTEM TRANSITION



Annex C:

Criteria used to review models in Chapter 4

This appendix explains the criteria used to review the attributes of different models summarised in Tables 4-1 and 4-2 of Chapter 4.

Policy Question I

[Scope] Competition in the electricity market

- Yes: The model determines market prices based on the generation costs and interactions of multiple technologies. This implies the model explicitly includes different generation costs for various technologies, with the price resulting from their interactions.
- This includes optimisation or equilibrium models that simulate cost-based merit-order dispatch, even if market prices are not explicitly calculated.
- The definition of "competition" includes:
    - System-level: Different technologies compete based on cost without an explicit market mechanism.
    - Market-level: Price varies based on competition across technologies.
    - Agent-level: Heterogeneous agents employ strategic bidding.

[Scope] Different sales channels

- Yes: The model simulates at least two different sales mechanisms—e.g., guaranteed purchase and spot market.
- Also includes models that simulate green electricity certificate (GEC) markets.
- No: If the model only includes subsidies (e.g. per kWh) without simulating different revenue channels.

[Scope] Power market bidding strategies

- Yes: The model includes technology-specific bidding behaviour and market-clearing processes, with differentiated marginal costs and outcomes.
- No: If supply is modelled as an aggregated block without technology-level bidding.

[Scope] Financing of investments

- Yes: The model includes factors relevant to financial modelling, such as interest rates, capital constraints, investment subsidies, or concessional loans.
- No: If the above factors are all absent, or only output-based subsidies (e.g., per kWh generated) are included.

[Scope] Investment decisions

- Yes: Investment choices (technology and capacity) are explicitly made by firms or agents based on expected returns.
- No: If the model uses centralised optimisation without modelling firm-level decision-making, even if model outputs include investment.

[Scope] All generation technologies

- Yes: Includes at least wind, solar, coal, hydro, nuclear, and gas.
- Also includes models that aggregate technologies into two categories, e.g., fossil and renewable.

[Scope] Dynamic technology costs

- Yes: The model allows for cost reductions over time, especially for VRE, through learning curves or external assumptions.
- Note that we denote cases in which technology costs are determined endogenously with Y-en.
- No: Technology costs are static over time.

[Scope] System stability

- Yes: The model includes technical constraints, such as ramp rates or integration limits, to reflect real-world dispatch feasibility.

[Structure] Temporal resolution

- Indicates the shortest time interval used in simulation or reporting (e.g., hourly, daily).

[Structure] Investment decision intervals

- For optimisation models: Refers to the planning horizon for investment decisions.

- For simulation models: Refers to the step size at which investment decisions are made (e.g., yearly).

[Structure] Geographical resolution

- Yes: If the model has sub-national granularity (e.g., grid zones, provinces, or representative nodes).

[Structure] Heterogeneous decision-making

- Yes: The model allows different agents (with the same technology) to respond differently due to differing characteristics or preferences.

[Policy options] Business-as-usual scenario

- Yes: Includes a clearly defined BAU scenario as a baseline.

[Policy options] Renewable Portfolio Standards (RPS)

- Yes: Explicitly includes RPS quotas in scenario design.

- Even if no certificate trading is modelled, a fixed RPS level counts as "Yes."

[Policy options] Carbon targets

- Yes: Model includes an explicit carbon reduction target or cap, or simulates a fixed emissions pathway.

[Policy options] Green electricity certificates

- Yes: The model simulates the price formation and trading process of green electricity certificates (GECs).

[Policy options] Investment CfDs

- Yes: CfD policies are modelled explicitly in scenarios.

[Policy options] Emissions trading scheme (ETS)

- Yes: The model simulates price formation in an ETS.

- No: If a fixed carbon price is applied, if there is no carbon price, or a shadow price from an optimisation model is used.

[Policy options] Other policy settings

- Yes: Model includes any other policy scenarios not already mentioned.
    - If any other financial support tools are modelled, mark as F.
    - If any other targets (modelled as constraints), regulatory policies, or planning requirements are modelled, mark as R.
    - If any other market-based mechanisms or pricing reforms are modelled, mark as M.

[Outputs] VRE installed capacity (GW)

- Yes: Model outputs include either new or total installed VRE capacity.

[Outputs] Installed capacity mix (% VRE)

- Yes: Model outputs show capacity shares or total capacity by technology.

[Outputs] Generation mix (% generation VRE)

- Yes: Outputs include generation (in GWh or %) by technology.

[Outputs] Thermal generation or emissions

- Yes: Model reports thermal power generation or carbon emissions (absolute or intensity-based).

Policy Question II

[Scope] Electricity spot market (or time-differentiated tariffs)

- Yes: The model explicitly simulates the process of real-time or time-differentiated electricity price formation, including supply bids, demand offers, and market clearing.
- This distinguishes spot markets from long-term markets by focusing on marginal rather than average cost pricing.
- Optimisation models that simulate dispatch constraints but do not model market price formation are marked "No".

[Scope] Ancillary services market

- Yes: The model explicitly simulates revenue from ancillary services or explicitly models the role of storage and other assets in system stability markets. Also includes demand-side response mechanisms that impact flexibility.
- No: If no ancillary service remuneration is modelled, or if only fixed capacity payments are modelled.

[Scope] Different revenue channels for storage

- Yes: The model simulates multiple revenue streams for storage assets (e.g., energy arbitrage, capacity leasing, capacity remuneration, or ancillary services), beyond just the energy-only market.

[Scope] Financing of investments

- Yes: The model includes firm-level capital cost constraints, power-specific interest rates, concessional financing, or investment subsidies.

[Scope] Investment decisions (including choice of technology and scale)

- Yes: The model simulates firm-level investment decisions based on expected profitability.
- No: If investment is decided via system-level optimisation with no firm-level behaviour.

[Scope] Multiple storage technologies

- Yes: The model includes at least two types of storage technologies (e.g. BESS and pumped hydro), allowing for competition among them.

[Scope] Dynamic technology costs

- Yes: The model incorporates endogenous or exogenous cost reductions for storage technologies (e.g., learning-by-doing or tech maturity).

[Scope] System stability

- Yes: The model includes ramp rate constraints or other technical limitations essential for assessing the integration of storage into the grid.

[Structure] Temporal resolution

- Refers to the finest time step used in the model's simulation output (e.g., hourly, 15-minute). Important for reflecting intra-day and seasonal variability in supply-demand balancing.

[Structure] Investment decision intervals

- For optimisation models: Refers to the time horizon over which investment planning is optimised.
- For simulation models: Refers to the discrete time step for investment decisions (e.g., annual, multi-year).

[Structure] Geographical representation

- Yes: Refers to geographical granularity (e.g., provincial-level or grid-region level).
- No: If it represents a single-node or national average without regional diversity.

[Structure] Heterogeneous decision making

- Yes: The model differentiates actors (e.g., firms) who, despite using the same technology, make different investment or operational decisions based on their characteristics or market context.

[Policy options] No dedicated security/flexibility policies

- Yes: The model includes a "no policy" scenario to serve as a baseline for comparison.

[Policy options] Capacity payments

- Yes: The model includes fixed payments for maintaining capacity, even if they are not varied across scenarios.

[Policy options] Energy storage mandate

- Yes: The model includes regulatory mandates for storage co-location or minimum targets for storage deployment.

[Policy options] Interprovincial trade

- Yes: The model explicitly includes regional power trading across provinces or grids, allowing for spatial balancing.
- No: If it assumes a single-region system without interconnection.

[Policy options] Capacity market auctions

- Yes: The model simulates competitive capacity auction mechanisms.
- No: If only fixed capacity payments are included.

[Policy options] Spot market liberalisation scenarios

- Yes: The model varies degrees of market liberalisation across scenarios (e.g., comparing day-ahead vs. real-time markets).
- No: If it only includes dispatch without modelling market price formation.

[Policy options] Other policy settings

- Yes: Model includes any other policy scenarios not already mentioned.
    - If any other financial transfer policies are modelled, mark as F.
    - If any other regulatory and planning requirements are modelled, mark as R.
    - If any other market-based mechanisms and pricing reforms are modelled, mark as M.

[Output] BESS installed capacity (GW)

- Yes: The model outputs the total or newly installed capacity of battery energy storage systems.

[Output] Flexible, low-carbon installed capacity

- Yes: Includes outputs for flexible, low-carbon technologies (e.g. BESS, pumped hydro, CCS-equipped thermal).

[Output] Installed capacity mix (% capacity VRE)

- Yes: The model reports the share or composition of installed capacity by technology.

[Output] Generation mix (% generation clean power)

- Yes: The model provides technology-specific electricity generation (e.g., % of generation from renewables, storage discharge).

[Output] Stability metrics

- Yes: The model reports metrics related to operational flexibility and reliability, such as:
    - Contribution to peak hours
    - Ramp rate coverage
    - Low-inertia period contributions
    - Hourly generation and BEES charging/discharging results

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