Enhancing China's ETS for Carbon Neutrality: Focus on Power Sector

Co-ordinating climate and renewable energy policy

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Abstract

The pace of emissions reductions of the People's Republic of China (hereinafter, "China") over the coming decades will be an important factor in global efforts to limit global warming to 1.5°C. The power sector is central to achieving China's stated climate ambition of peaking CO_2 emissions before 2030 and achieving carbon neutrality before 2060. Accelerating the sector's decarbonisation requires a well-coordinated policy mix. This report, *Enhancing China's ETS for Carbon Neutrality: Focus on Power Sector*, responds to the Chinese government's invitation to the IEA to co-operate on carbon emissions trading systems (ETS) and synergies across energy and climate policies. It shows that an enhanced ETS could lead the electricity sector toward an emissions trajectory that is in line with China's carbon neutrality target. This report also explores the interactions and effects of China's national ETS with its renewable energy policy in the electricity sector, namely renewable portfolio standards (RPS). It examines the impact of different Enhanced ETS Scenarios on CO_2 emissions, generation mix, cost-effectiveness and interaction with RPS. The report concludes with a series of policy insights to inform China's climate and energy debate.

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Table of contents

List of figures

List of boxes

List of tables

Executive summary

The statement by President Xi Jinping in September 2020 that the People's Republic of China (hereinafter, "China") will "aim to have CO_2 emissions peak before 2030 and achieve carbon neutrality before 2060" sets out a clear vision and timeline for a profound transformation of the country's socio-economic development. The pace of China's emissions reductions over the coming decades will be an important factor in global efforts to limit global warming to 1.5°C. The power sector, responsible for nearly half of the country's energy sector CO_2 emissions,[1] is central to achieving China's climate ambition. Policy makers need to set the incentives and market structures which ensure that power sector actors can capture the dynamic development and rapid cost reduction of low-carbon technologies, and improve the management of the existing fleet of fossil-based generation through retrofitting, repurposing and retirement.

Accelerating power sector decarbonisation in support of the carbon neutrality goal requires an effectively co-ordinated policy mix. This report responds to the Chinese government's invitation to the IEA to co-operate on carbon emissions trading systems (ETS) and synergies across energy and climate policies. It explores the interactions and effects of China's national ETS with its renewable energy policy in the electricity sector, namely renewable portfolio standards (RPS). The report demonstrates how the policy mix could be better co-ordinated and explores possible pathways that an enhanced ETS could lead the electricity sector toward an emissions trajectory that is in line with China's carbon neutrality target.

China's national ETS came into operation in 2021 and is the world's largest ETS, covering annual power sector emissions of around 4.5 Gt CO_2. It currently employs an intensity-based design with free allocation. This means that allowances are allocated to covered entities for free according to actual production levels of coal- and gas-fired power plants (e.g. kWh of electricity generated) and predetermined emissions intensity benchmarks (e.g. in g CO_2/kWh) covering only coal- and gas-fired power plants. This is different from most ETS systems such as the EU ETS, which set a predetermined absolute cap on covered emissions. Four emissions intensity benchmarks are currently defined in China's national ETS for coal- and gas-fired power plants, and are differentiated based on fuel, sub-technology and plant size.

Against this backdrop, this report analyses five policy scenarios for the electricity sector for 2020 to 2035, consistent with China's 14th Five-Year Plan (2021-2025)

[1] Energy sector CO_2 emissions include CO_2 emissions from fuel combustion and from industrial processes.

and the Long-Range Objectives through the Year 2035 (China, State Council, 2021a). In order to test the impact of different ETS designs, assumptions regarding electricity demand growth, exogenous technology cost evolutions and the current RPS policy set-up are kept identical across all scenarios. Taking into account China's ongoing electricity market reform, all scenarios assume economic dispatch from 2025 – an important element to effectively integrate the CO_2 price signal in operational, investment and consumption decisions.

The first two scenarios establish a counterfactual and examine current policy. The **RPS Scenario** establishes a hypothetical counterfactual scenario with the current RPS policy set-up, including a target on the share of non-hydro renewables which is assumed to increase to 25.9% in 2030 and 36.0% in 2035, but no emissions control or carbon pricing policy.[2] This scenario provides a point of comparison for isolating and evaluating ETS effects. The **RPS-ETS Scenario** is a current policy scenario with the same RPS policy assumptions, and an intensity-based ETS with free allocation as currently implemented. The scenario assumes moderate tightening of allowance allocation benchmarks over time.

In addition, three **Enhanced ETS (ETS+) Scenarios** explore different ETS design enhancements after 2025, while keeping the same RPS policy assumptions as the RPS and RPS-ETS Scenario: **ETS+Benchmark (BM) Scenario** maintains the intensity-based free allocation but with significantly tighter benchmarks; **ETS+Auction Scenario** maintains intensity-based allocation with moderate benchmark tightening and introduces partial allowance auctioning; and **ETS+Cap Scenario** changes ETS design significantly through a transition from the intensity-based ETS to a cap-and-trade system. The three ETS+ Scenarios are designed to achieve an electricity sector emissions trajectory after 2025 that is better aligned with China's stated goal of carbon neutrality before 2060. All ETS+ Scenarios use the same emissions trajectory of the IEA's Announced Pledges Scenario (APS)[3] as input, and demonstrate the impact of potential future ETS designs.

[2] The share target of non-hydro renewables is based on China's National Energy Administration's consultation draft (China, NEA, 2021a).

[3] As presented in the IEA's publications "An energy sector roadmap to carbon neutrality in China" and "World Energy Outlook 2021". There is no single pathway for energy sector emissions consistent with China's stated goals of achieving a peak in CO_2 emissions before 2030 and carbon neutrality before 2060. The Announced Pledges Scenario (APS) presents one plausible pathway to carbon neutrality in China's energy sector in line with the country's stated goals. "An energy sector roadmap to carbon neutrality in China" also explores an Accelerated Transition Scenario (ATS) to assess the opportunities for and implications of a faster transition through enhanced climate policy ambitions and efforts to 2030.

The table below summarises the key ETS design features and outcomes of each scenario, excluding the hypothetical counterfactual scenario:

Table ES.1 Key outcomes by scenario, 2035

Scenario	Key ETS design features	CO_2 reduction (from 2020)	Main driver of CO_2 reductions	Increase in total system costs*	Additional renewables share**	Interaction with RPS
RPS-ETS	Intensity-based; Moderate BM tightening; Free allocation	-20%	CCUS	-/-	-/-	Low
ETS+BM	Intensity-based; Strong BM tightening; Free allocation	-38%	CCUS	5.2%	1%	Low
ETS+Auction	Intensity-based; Moderate BM tightening; Partial auctioning	-38%	Renewables CCUS	1.4%	8%	High
ETS+Cap	Cap-and-Trade; Stringent cap; Free allocation	-38%	Renewables	0%	12%	High

*Increase in total system costs relative to the RPS-ETS Scenario required to achieve given CO_2 reduction level.
**Additional share of non-hydro renewables in electricity generation mix relative to the RPS-ETS Scenario.

Electricity sector emissions peak before 2030 with current RPS and ETS policies

Implementation of the RPS-ETS Scenario can almost triple CO_2 emissions reductions by 2035 relative to 2020 compared to an RPS only scenario. Together, both policies can result in electricity-related emissions falling after 2025, and decreasing to 20% below 2020 levels by 2035. In the near- and medium-term, both policies could work in tandem to successfully peak and reduce absolute CO_2 emissions from the electricity sector. The two policies act on different power generation sources with limited overlaps, delivering emissions reductions that are complementary.

The intensity-based ETS enhances the efficiency of the existing coal power fleet and the RPS drives renewables generation. Implementing the RPS policy, targeting around 36% of non-hydro renewables in the generation mix by 2035, drives significant new capacity additions from mainly variable renewable energy (VRE) sources such as wind and solar PV. An intensity-based ETS with gradually tightening benchmarks covering coal and gas (RPS-ETS Scenario) drives higher coal fleet efficiency, including through incentivising retrofits and a shift in coal power generation to the most efficient plants. It also supports curbing new additions of unabated coal in favour of carbon capture, utilisation and storage (CCUS) technology deployment. However, the current ETS design provides very limited incentive for switching away from coal generation to non-fossil sources and does not lead to additional renewables deployment.

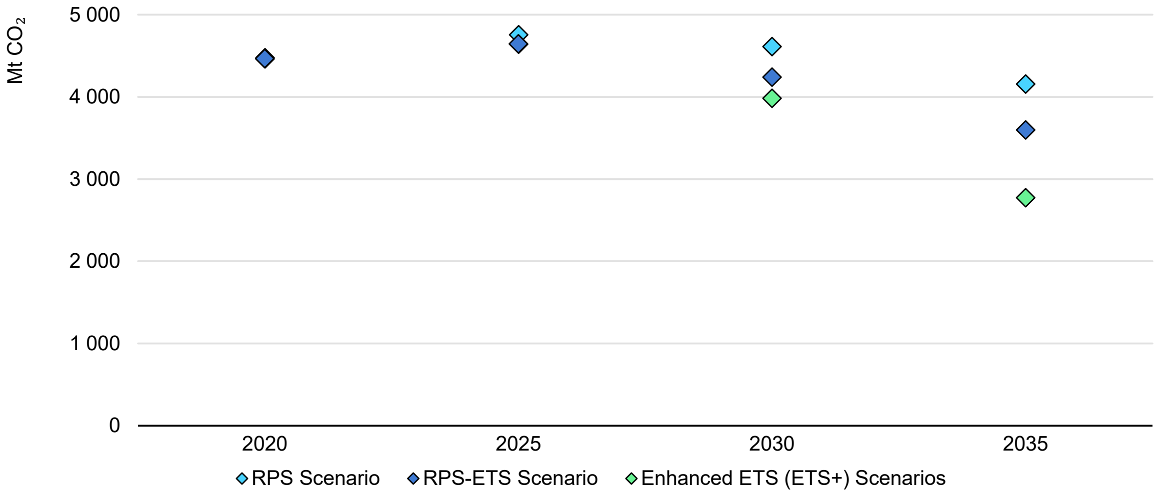
China's intensity-based ETS design with free allowance allocation currently only permits the active participation of fossil-based generation. This is because allowances are calculated and allocated through fuel- and technology-specific benchmarks for coal and gas power plants only, while non-fossil generation sources are not covered by the benchmarks. Power generators with an emissions intensity higher than the benchmarks experience an allowance deficit. However, this can only be balanced by an allowance surplus from power generators covered by benchmarks, and that have a lower emissions intensity than those benchmarks. Generation sources that are not covered by the benchmarks – such as renewables – cannot take part in the current ETS except through the very limited route of Chinese Certified Emissions Reductions (CCERs). Switching to non-fossil generation sources could allow a generator to avoid an allowance deficit and the associated cost of needing to acquire additional allowances. However, since non-fossil sources do not receive allowances, they cannot help balance allowance deficits, nor can non-fossil generators benefit from surplus allowances that can be sold. This ETS design of fuel- and technology-specific benchmarks for only coal and gas power, therefore, mainly lowers the emissions intensity of benchmark-covered generation sources, including through CCUS, while providing very limited encouragement for fuel switching to non-fossil sources.

Enhancements in ETS design can accelerate electricity sector alignment with a carbon neutrality trajectory

Stronger decarbonisation than in the RPS-ETS Scenario would better align the electricity sector with China's carbon neutrality goal. In order to support economy-wide carbon neutrality before 2060, China's power sector would likely need to achieve net zero CO_2 emissions before 2055 (IEA, 2021a). Accelerating the transition of the electricity sector would not only further reduce CO_2 emissions from the biggest source in China but also maximise the sector's role in decarbonising end-use sectors, as growing electrification with an increasingly decarbonised electricity sector would further reduce overall emissions. Avoiding new unabated coal capacities and a faster transition also increase the chances of reaching carbon neutrality in an orderly fashion and reduce the potential burden of emissions lock-in and stranded assets (IEA, 2021a).

ETS design changes can double the CO_2 reduction of the RPS-ETS Scenario and accelerate alignment with a carbon neutrality emissions trajectory. In the ETS+ Scenarios, electricity sector emissions are 38% lower by 2035 compared to 2020 – nearly double the reductions as in the RPS-ETS Scenario. Different ETS enhancements could drive these additional emissions reductions. If retaining the current design – an intensity-based ETS with free allocation – the benchmark tightening rate would need to be doubled in 2025-2030 and almost quadrupled in 2030-2035 (ETS+BM Scenario), compared to the RPS-ETS Scenario. This would reduce coal benchmarks to two-thirds of their 2020 levels by 2035. In the ETS+Auction Scenario, around a quarter of allowances would need to be auctioned by 2035 while maintaining the same tightening rate for coal benchmarks as in the RPS-ETS Scenario. A third option (ETS+Cap Scenario) is to introduce an absolute emissions cap that is aligned with a carbon neutrality pathway.

Figure ES.1 CO_2 emissions trajectory from electricity generation by scenario, 2020-2035

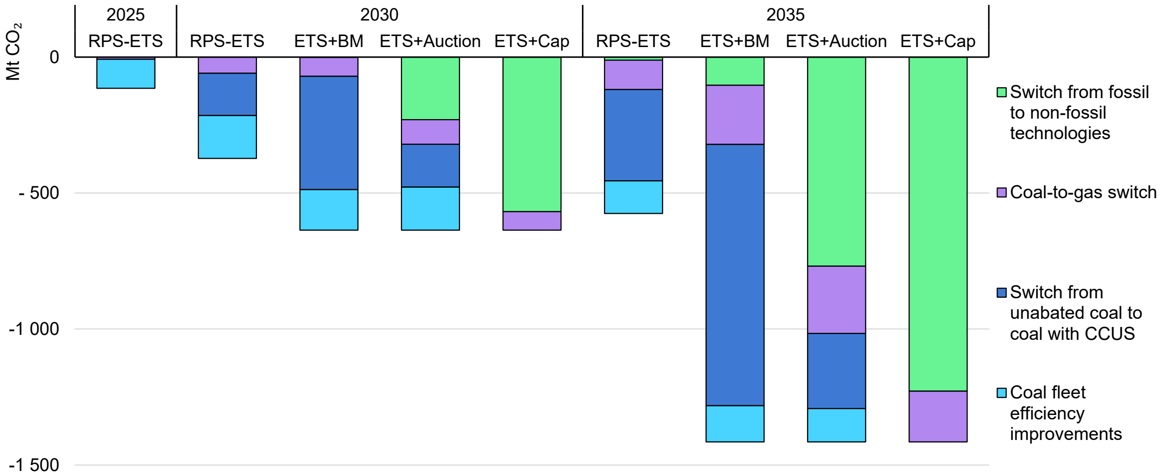


Stringent ETS benchmarks drive efficiency and CCUS; auctioning and a cap encourage fuel switching

Depending on its design, the ETS can drive emissions reductions through different channels. In an intensity-based ETS with fully free allocation through coal and gas power benchmarks (RPS-ETS and ETS+BM Scenarios), the ETS delivers most of the emissions reductions by transforming the coal fleet through improving unabated coal fleet efficiency and encouraging CCUS adoption in coal power from 2030 onwards. With increased benchmark stringency, the ETS+BM Scenario triples CCUS-related reductions compared to the RPS-ETS Scenario in 2035, with some very limited fuel switching from coal to gas and non-fossil technologies. The ETS+Auction Scenario generates most of the emissions reductions through fuel switching to non-fossil technologies, mainly onshore wind and solar PV, and to a lesser degree to gas, as well as through CCUS deployment. The scenario's effect on fuel switching to gas and unabated coal fleet efficiency improvements is similar in magnitude to that in the RPS-ETS and ETS+BM

Scenarios. On the other hand, transitioning from an intensity-based ETS to a cap-and-trade design with a stringent cap could significantly change how the ETS drives decarbonisation. In the ETS+Cap Scenario, emissions reductions result entirely from fuel switching away from coal power – around 90% to non-fossil and 10% to gas power. While technical efficiency improvements of the coal fleet also take place in this scenario, the average operational efficiency does not improve as all coal units see a reduction in running hours.

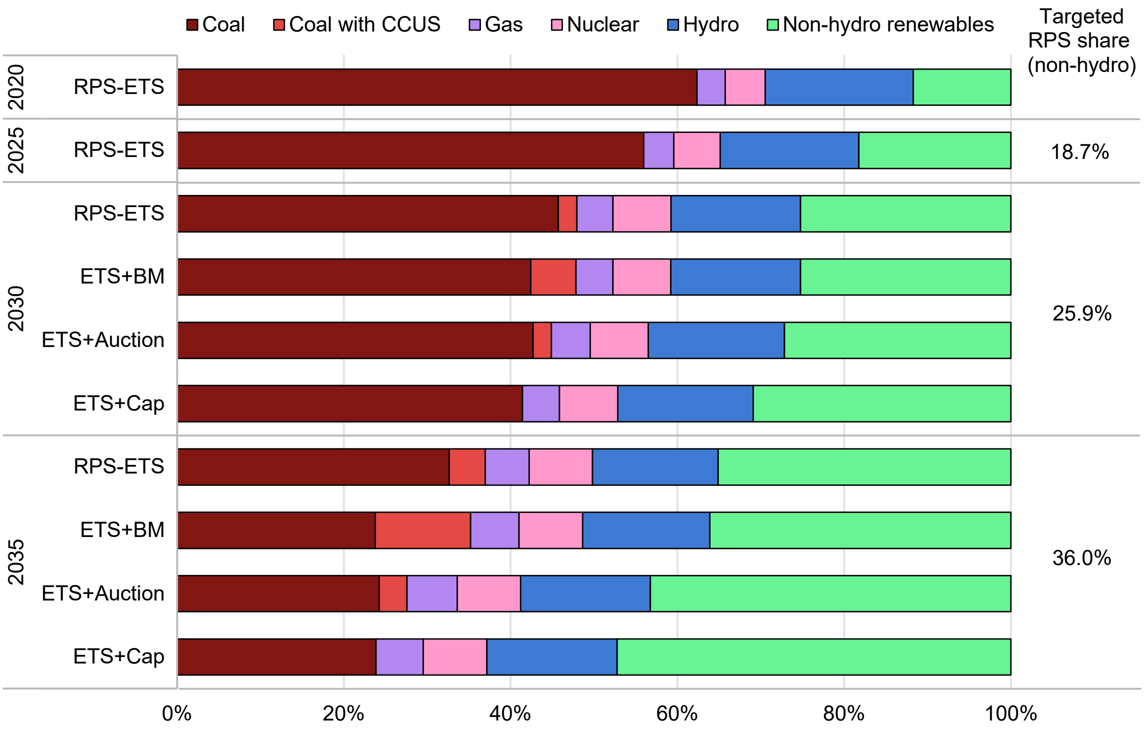
Figure ES.2 Additional emissions reductions by channel in the RPS-ETS and ETS+ Scenarios compared with the counterfactual RPS Scenario, 2025-2035



The introduction of allowance auctioning and a transition to a stringent cap-and-trade considerably increase the ETS incentive for fuel switching. Partial auctioning (ETS+Auction Scenario) – leading to a reduction in free allocation through coal and gas power benchmarks – raises the effective CO_2 cost for covered fossil-based generation sources. It thus makes them more expensive to run compared with non-fossil generation technologies, thereby encouraging switching to renewables. At the same time, the intensity-based design still encourages higher fleet efficiency and some CCUS deployment. Transitioning to a cap-and-trade system (ETS+Cap Scenario) with a stringent emissions cap would further change the ETS impacts on technologies. By setting a predetermined emissions cap and moving away from technology-specific benchmarks, a cap-and-trade allows the participation of all generation sources in achieving absolute emissions reductions, instead of focusing on emissions intensity reduction of coal and gas power. Its design incentivises generators to reduce CO_2 emissions through the lowest-cost abatement options, thus spurring emissions reductions mainly through fuel switching to cost-competitive renewables.

Enhanced ETS designs lead to very different generation mixes, but all accelerate the phase-down of unabated coal. In all ETS+ Scenarios, unabated coal power plants would generate 2 800 TWh of electricity by 2035 compared with around 4 800 TWh in 2020; unabated coal's share of the generation mix would also decline from more than 60% in 2020 to 24% in 2035. This is compared with a 33% generation share in the RPS-ETS Scenario by 2035, noting that in all scenarios total electricity generation increases by more than 50% between 2020 and 2035. The different enhanced ETS designs drive different low-carbon solutions. In the ETS+BM Scenario, where the benchmarks of an intensity-based ETS are significantly tightened, the share of coal power generation with CCUS increases to 11% of total generation by 2035. The shares of non-fossil technologies remain similar to those of the RPS-ETS Scenario. Introducing partial auctioning in the intensity-based ETS (ETS+Auction Scenario) results in the most diverse set of decarbonisation solutions. It encourages additional renewables and CCUS deployment, as well as some efficient gas generation and coal fleet efficiency improvement. By 2035, the share of renewables generation reaches nearly 60%, with non-hydro renewables standing for 43%. Meanwhile, CCUS-equipped coal power contributes 3%. Transitioning to a cap-and-trade system with a stringent emissions cap (ETS+Cap Scenario) leads to a generation mix dominated by renewables. These would account for 63% of total generation by 2035, including 47% of non-hydro renewables – around 12% higher than in the RPS-ETS Scenario. This suggests that a cap-and-trade system could significantly accelerate the deployment of mature renewables. In the ETS+Cap Scenario, no coal power with CCUS is deployed by 2035.

Figure ES.3 Electricity generation mix by technology and scenario, 2020-2035



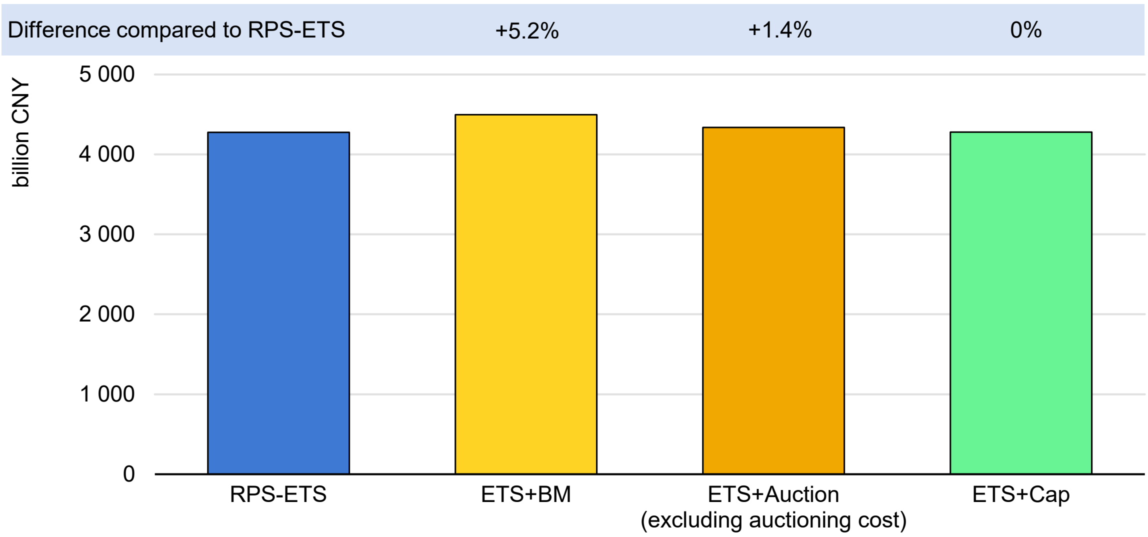
An ETS with a cap-and-trade can double CO_2 emissions reductions at no additional cost

All three Enhanced ETS Scenarios can achieve the same emissions trajectory for the electricity sector, but at different costs. Total system cost[4] increases significantly over time across all scenarios due to increasing electricity demand: in the RPS-ETS Scenario, total system cost increases from 2.80 trillion Chinese Yuan Renminbi (CNY) (USD 434 billion) in 2020 to CNY 4.28 trillion (USD 664 billion) in 2035. With the same electricity demand growth assumption, the ETS+Cap Scenario leads to the lowest total system cost for the electricity sector across all Enhanced ETS Scenarios. In 2035, it has the same system cost as the RPS-ETS Scenario but with almost 20% additional CO_2 emissions reductions. This is followed by the ETS+Auction Scenario with slightly higher costs (CNY 4.34 trillion, USD 673 billion), and the ETS+BM Scenario which is 5% more costly than the RPS-ETS Scenario (CNY 4.49 trillion, USD 698 billion). In addition, auction revenues generated in the ETS+Auction Scenario could reach CNY 260 billion (USD 40 billion) in 2035, which can be used to address

[4] In this report, total system cost includes annualised capital expenditure as well as variable and fixed operating and maintenance costs of electricity generation, transmission and balancing costs, and costs for plant retrofits.

affordability or competitiveness concerns of electricity consumers, as well as to invest in technology innovation and energy efficiency to reduce future decarbonisation cost.

Figure ES.4 Total system costs by scenario, 2035



Note: Auctioning cost is the cost of a generator to purchase one Chinese Emissions Allowance (CEA) in allowance auctions. For the comparison on total system costs we exclude the auctioning cost for the ETS+Auction Scenario because, from a system perspective, auctioning costs and revenues can be balanced.

The cap-and-trade system achieves this cost-effectiveness by prioritising the lowest-cost abatement opportunities, especially fuel switching. By allowing power sector actors to freely choose the cheapest abatement technology, the cap-and-trade system introduces technology neutrality which, in turn, drives fuel switching from unabated coal generation to renewables. In contrast, the ETS+BM Scenario results in a much more costly generation mix as it would primarily encourage a shift from unabated coal to coal power with CCUS, a less mature and more expensive abatement option. Introducing auctioning into the intensity-based ETS (ETS+Auction Scenario), raises the effective CO_2 cost that generators face and encourages both some fuel switching to renewables and intensity improvements in the coal fleet including through CCUS. Consequently, in the ETS+Cap Scenario, fuel switching to mature renewables can be encouraged already with a relatively low allowance price level of CNY 100/t CO_2 (USD 16/t CO_2) by 2035. In contrast, an intensity-based ETS (in both ETS+BM and ETS+Auction Scenarios) would lead to a higher allowance price of around CNY 300/t CO_2 (USD 47/t CO_2) by 2035 to achieve the same emissions trajectory. This is because the ETS design drives emissions reductions at least in part through CCUS deployment which requires higher financial support.

Evolution of ETS and RPS require a policy co-ordination process to strengthen their effectiveness

Simultaneous operation of the RPS and ETS policy mix can have important interaction effects which need to be taken into account in policy design. Where the RPS and ETS act on different electricity generation assets, as in the RPS-ETS Scenario which models the current policy set-up, both work alongside each other and with limited interaction. However, with potential changes in the ETS design, and as renewables account for a greater share in the electricity sector, overlaps between the ETS and the RPS lead to a greater need for policy co-ordination. The results of this report show that a cap-and-trade ETS (ETS+Cap Scenario), as well as partial auctioning (ETS+Auction Scenario), can help to provide the financial incentives needed to increase renewables deployment.

While these changes in ETS design can make it a key instrument in further decarbonising the electricity sector, and ensuring alignment with a carbon neutrality pathway at a lower cost, the ETS price incentive could directly interact with the green certificate price of the RPS. International experience also shows that in a cap-and-trade ETS, higher than expected renewables deployment can lead to allowance price decreases, which in turn can reduce incentives for technological innovation and increase decarbonisation costs overall. These interactions highlight the importance for policy makers to regularly assess the impacts of changes to China's energy and climate policies. Strengthened policy co-ordination should aim to improve the effectiveness of the policy mix, and support achieving economy-wide carbon neutrality at the lowest cost possible.

Policy Insights

As China's carbon neutrality target shifts the policy focus from improving emission intensities towards achieving absolute emissions reductions, policy makers could consider the following insights to accelerate the alignment of the electricity sector with a 2060 carbon neutrality target through an enhanced ETS:

- **Carefully examine different ETS design options in line with the intended policy objectives**, in particular with a view to the resulting costs, the carbon price and the technology mix. While different design approaches can achieve the same emissions trajectory, they could serve different policy priorities, such as supporting different technologies from renewables to CCUS. Consequently, they would also require different levels of co-ordination and companion policies (e.g. adjusting target level and RPS focus on less mature renewables, support for transport and storage infrastructure necessary for CCUS deployment).
- **Communicate future plans on China's ETS design well in advance**, including the medium-term benchmark and/or cap trajectory (e.g. for the next 5-10 years), to provide visibility and planning certainty for market participants. This will guide

plant management and investment decisions (including for technology innovation), and accelerate alignment with carbon peaking and carbon neutrality goals.

- **Establish a policy co-ordination process** involving all relevant government institutions that aims to analyse ex-ante the impact of different policy mixes to avoid unintended side-effects, and which regularly reviews policy outcomes. Consider introducing flexibility mechanisms such as allowance reserves or price corridors to help accommodate unexpected policy interactions and external shocks.
- **Consider gradually introducing allowance auctioning** in the current 14th Five-Year Plan (FYP) period (2021-2025) to incentivise more diversified and lower-cost emissions abatement options, encouraging renewables in addition to fossil-based generation improvement and CCUS deployment. This would also enable the use of auction revenues to address distributional impacts and competitiveness concerns, as well as to directly invest in climate actions such as low-carbon technology innovation and energy efficiency.
- **Consider transitioning to a cap-and-trade system with a stringent cap** later in the decade to position the ETS as a key instrument in China's path to carbon neutrality, to reduce the number of additional policies targeting renewables, and to lower the cost for decarbonisation. The deployment of CCUS could still be incentivised through special provisions within an ETS, such as additional free allowances, or through companion policies dedicated to CCUS uptake.
- **Swiftly implement announced plans to extend the ETS to other sectors, and consider opening market participation to non-compliance entities** such as financial intermediaries. Sectoral extension would reduce costs by expanding possible options for emissions reductions, and establish a cross-sectoral carbon price signal to help achieve carbon neutrality. Opening participation would also increase the ETS' liquidity and facilitate price discovery through a larger number of actors trading allowances.

Chapter 1. Policy context

Responsible for nearly half of the country's energy sector CO_2 emissions[5], the power sector is central to achieving China's climate ambitions. Its accelerated decarbonisation requires an effectively co-ordinated policy mix that can support the development of low-carbon technologies, manage existing fossil-based infrastructure, and maximise its key role in decarbonising end-use sectors via electrification. This chapter first provides a brief overview of the latest developments in China's power sector, emissions trading system and renewables support policy in the context of China's carbon neutrality goal. It then discusses potential interactions between emissions trading and renewables policy drawing from international experiences.

Long-term policy objectives

At the United Nations General Assembly in September 2020, President Xi Jinping announced that China aims to have CO_2 emissions peak before 2030 and to achieve carbon neutrality before 2060. In October 2021, China released a high-level Guidance document for achieving the announced targets (hereafter "the Guidance") (China, CCCPC and State Council, 2021), and an Action Plan to peak CO_2 emissions before 2030 (China, State Council, 2021b). These targets were also reflected internationally in China's updated Nationally Determined Contribution (NDC) under the Paris Agreement for 2030, and in its first long-term low greenhouse gas emission development strategy (China, State Council, 2021c, 2021d). China's updated NDC also includes targets for lowering CO_2 emissions per unit of GDP by over 65% from the 2005 level, increasing the share of non-fossil fuels in primary energy consumption to around 25%, increasing the forest stock volume by 6 billion cubic meters from the 2005 level, and expanding its total installed capacity of wind and solar power to over 1 200 GW by 2030. For its long-term carbon neutrality goal, the country set a target to increase the non-fossil energy share to over 80% by 2060.

The high-level Guidance anchors China's policy framework on the climate goals, guiding the formulation of more detailed sectoral and regional policies. The Guidance highlights the need to accelerate the development of a low-carbon and efficient energy system, including by significantly improving energy efficiency, increasingly transforming the energy mix from fossil fuels to non-fossil energy, and deepening energy system reforms. For the near- and medium-term, China aims

[5] Energy sector CO_2 emissions include CO_2 emissions from fuel combustion and from industrial processes.

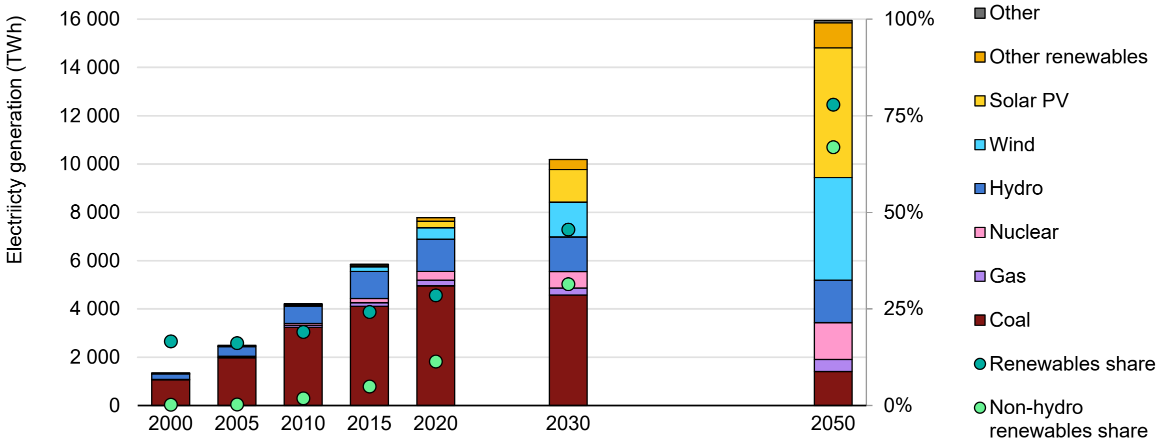
to limit the increase in coal consumption over the 14th FYP period (2021-2025) and to phase it down in the 15th FYP period (2026-2030), develop a new power system based on new energy sources (mainly wind and solar) and advance market-oriented reforms in the power sector.

Among key policy mechanisms for achieving the climate goals, the Guidance identified the need to accelerate the development and improvement of carbon pricing mechanisms and the market-based national emissions trading system (ETS), which began trading in July 2021 and covers, in its initial phase, coal- and gas-fired power plants responsible for around 4.5 Gt of annual CO_2 emissions. The Guidance also underlined the need to better co-ordinate the trading of electricity, energy consumption permits and carbon emissions allowances. Furthermore, the Guidance and the CO_2 Emissions Peaking Action Plan aim to improve innovation mechanisms and systems, enhance innovation capability and accelerate R&D and application of low-carbon technologies, such as for large-scale renewables integration, advanced energy storage, hydrogen and CCUS.

China’s power sector

China accounted for nearly 30% of global electricity generation (7 800 TWh) in 2020, with its electricity production rising over 80%, or 6% annually, between 2010 and 2020. Despite the Covid-19 pandemic, the country saw a 3.7% annual increase in electricity generation in 2020 compared to 2019, and strong growth at 8% in 2021 to 8 100 TWh. China’s electricity demand is expected to continue to grow, though at a slower pace than in the last decade, with electricity generation estimated to double by 2050 in IEA’s Announced Pledges Scenario (APS) (Figure 1.1) (IEA, 2021b).

Figure 1.1 China electricity generation and projections in the Announced Pledges Scenario, 2000-2050



Note: The Announced Pledges Scenario (APS) is presented in IEA’s World Energy Outlook 2021. It takes account of all of the climate commitments made by governments around the world, including Nationally Determined Contributions as well as longer term net zero/carbon neutrality targets, and assumes that they will be met in full and on time.

Coal power

Electricity generation in China remains highly reliant on coal as electricity demand undergoes sustained growth, despite efforts to limit coal consumption and the fast expansion of alternative sources in the recent decade. Coal fuelled over 60% of electricity produced in 2020, followed by hydropower (17%), wind (6%) and nuclear (5%). Solar PV and natural gas both contributed around 3% (IEA, 2021b). The share of coal in the generation mix is expected to fall below 60% by 2025, as renewable energy sources are set to meet the majority of additional demand, but coal is still expected to meet around a quarter of the increment during 2022-2024 (IEA, 2022a).

The dominance of coal led to emissions of almost 4.8 Gt CO_2 from electricity generation in China in 2020,[6] corresponding to 14% of global energy sector CO_2 emissions and over 40% of China's energy sector emissions (IEA, 2021b).[7] Of China's emissions from electricity generation, over 95% came from coal-fired power plants. Similarly, in 2021, coal power in particular was called on to meet an unprecedented increase in China's electricity demand, in turn contributing to the highest level of global CO_2 emissions ever (IEA, 2022b). In 2020, China had 1 080 GW of installed coal-fired power capacity – more than half of global coal capacity. The young age of the coal fleet increases the risk of locked-in emissions: the average plant age is only 13 years, with 40% of coal plants having been built in the last ten years. In addition, there were nearly 250 GW of new capacity at various stages of development (CEC, 2021; IEA, 2021a). While most recently built coal plants are large-scale supercritical or ultra-supercritical plants with high efficiency, less efficient plants such as subcritical plants still represent almost half of China's coal capacity in operation.

Existing coal-fired power plants could account for around 60% (101 Gt CO_2) of total cumulative emissions (175 Gt CO_2) from China's existing energy infrastructure between 2020 and 2060, equivalent to nine years of China's energy sector emissions in 2020[8] (IEA, 2021a). Limiting new coal power capacity additions and managing the coal-powered fleet through retrofitting, repurposing and early retirement, will be key to China's clean energy transition and achieving carbon neutrality. A 2021 Plan to retrofit and upgrade coal-fired units aims to

[6] The IEA and China's estimates for electricity sector emissions differ due to methodological differences, including how power sector emissions are attributed between heat and electricity generation in co-generation plants, and to emissions factors used for fossil fuel sub-categories. For the purpose of this report and to evaluate country-specific policy impacts, electricity sector emissions used for modelling (Chapters 2-4) are estimated using China's methodology, resulting in around 4.5 Gt CO_2, and are therefore lower than the IEA's estimate (see Annex A for more information).
[7] Energy sector emissions include energy-related and industrial process CO_2 emissions.
[8] The analysis on emissions from existing infrastructure uses 2020 as the base year and assumes that the existing energy infrastructure are operated under the typical operating conditions (e.g. capacity factors, fuel shares and mileages) and that no assets are retired early or modified. Typical lifetimes of coal power plants and heavy industry assets in China of 25-35 years are used. The analysis does not include energy infrastructure that are planned to be built in the coming years.

reduce the average energy intensity of thermal power from 305.5 grammes of standard coal equivalent per kilowatt hour (gce/kWh) in 2020 to 300 gce/kWh by 2025, and targets flexibility retrofits[9] for 200 GW of coal-fired capacity. New coal-fired units are still allowed, subject to strict approval and in principle can only be ultra-supercritical units with energy intensity below 270 gce/kWh (China, NDRC and NEA, 2021a).

Renewables

Despite the continued dominance of coal, China is the global leader in the deployment of renewables, including solar PV, wind and hydro. By 2020, China increased its renewable capacity to over 930 GW (including pumped storage hydropower), exceeding the capacity target for the 13th FYP period (2015-2020) of 715 GW by 30%. Hydropower has accounted for 35% of total renewable capacity additions since 2000. Another 60% of renewable capacity additions since 2000 has come from solar PV and wind power. By the end of 2020, China had installed capacity of over 280 GW of wind and over 250 GW of solar PV, and further added over 100 GW of wind and solar combined capacity in 2021. As part of its updated NDC, China has announced a target to increase the total capacity of wind and solar power to over 1 200 GW by 2030. China's renewables-based electricity generation reached 2 200 TWh in 2020, meeting nearly 30% of electricity demand (China, State Council Information Office and NEA, 2021), compared to 16% in 2000. The renewables expansion, together with that of nuclear power and fossil-based power plants' efficiency improvement, helped drive down the carbon intensity of electricity generation by around 30% between 2000 and 2020 (IEA, 2021a).

Renewables, in particular wind and solar PV, will need to continue their massive scale-up in the power sector to support China's carbon peak and carbon neutrality goals. In the IEA's Announced Pledges Scenario (APS), the share of renewables in electricity generation reaches over 45% in 2030 and nearly 80% in 2050. Reaching these shares would require strong investment in renewable generation resources, but also investment in electricity system flexibility, including power plant flexibility, storage capacities, demand-side response and electricity networks, as well as adaptations in policy, regulatory and market frameworks to enable secure and efficient integration of a high share of variable renewables (IEA, 2021b, 2018).

[9] Examples of flexible retrofits include retrofits that can reduce the minimum stable level at which a plant can operate, replacement of old equipment and operations updates in order to enhance a power plant's capacity to provide flexibility to the grid.

Power system reform

Alongside the transformation of the generation mix and infrastructure, China's power sector is currently undergoing wide-ranging regulatory reforms to expand the use of market-based mechanisms to determine power sector operations and improve system efficiency. This has important impacts for the function of China's ETS (Box 1.1). Electricity dispatch and pricing has predominantly been determined administratively in China. Important reforms under Policy Document No. 5 in 2002 restructured the power system by separating the power generation and transmission functions of the vertically integrated utility, strengthening regulation, and introducing initial elements of more competitive power markets. A new major round of power system reforms was launched in 2015 with the publication of Document No 9, which aims to enhance the market's role in electricity pricing, reduce electricity prices, increase industrial productivity and boost economic growth (China, CCCPC and State Council, 2015). Implementation is underway, including establishing mid- to long-term electricity forward markets where wholesale energy prices are decided by negotiation or auction between generators or suppliers and large consumers, broadening ancillary services markets, and piloting spot markets which enable day-ahead, real-time energy exchanges. Since 2019, China has taken steps to liberalise the pricing of coal-fired power, turning the regulated coal benchmark pricing to a "base price + fluctuation" system, and allowing coal power prices to fluctuate by 10% upwards and 15% downwards from benchmark price levels (China, NDRC, 2019). In October 2021, in a major step towards market pricing of electricity, further reforms took place which allowed coal-fired power prices to rise or fall by up to 20% from benchmark price levels, and removed price fluctuation limits for energy-intensive firms and electricity spot trading, (China, NDRC, 2021a). With electricity markets currently operating at provincial and regional levels, China also aims to accelerate the establishment of a nation-wide electricity market by 2025 to further optimise resources allocation, including through increased interprovincial power trade, as well as to improve the stability and flexibility of the power system, and to better support renewables integration (China, NDRC and NEA, 2022a).

Box 1.1 The importance of the power market reform for China's ETS

The effectiveness of China's ETS is closely related to the progress in power market reform, in particular to economic electricity dispatch decisions. A transition from administratively-determined dispatch to economic dispatch, where the power plant with the lowest generation costs has priority for meeting electricity demand, has profound implications for promoting the use of efficient, low-emissions, and least-cost generation resources. Economic dispatch would strengthen the effectiveness of the ETS by allowing markets to reflect carbon prices in electricity generation costs and thus to directly impact dispatch decisions. Without this reform, the ETS risks playing a limited role in reducing power sector emissions; coal power plants would not need to adjust their operation in response to the price signal stemming from the ETS allowance allocation (IEA, 2020a, 2021c). Transitioning to an economic dispatch mechanism would also allow cost pass-through from generators to energy consumers, and hence strengthen incentives for demand-side response. At the same time, it would require co-ordination in policy and market designs to manage implications for equity, energy affordability and competitiveness. Together, power market reforms and effective carbon pricing could help to significantly reduce power system operational costs, improve wind and solar power integration, and achieve a considerable drop in power sector emissions (IEA, 2019).

China’s ETS design

China’s national emissions trading system (ETS) was officially launched in 2017 and came into operation in July 2021, ten years after the country announced it would develop regional pilot carbon markets, several of which began operating in 2013. The national ETS currently covers the power sector (electricity and heat generation[10]), involving more than 2 000 companies and covering around 4.5 Gt CO_2 or around 40% of China’s energy sector CO_2 emissions in 2020.[11] Already the largest ETS in the world, the coverage of China’s ETS is expected to expand to include other energy-intensive sectors, which account for around 30% of China’s energy sector CO_2 emissions, including petrochemicals, chemicals, building materials, iron and steel, non-ferrous metals, paper and domestic aviation. The first compliance period of the national ETS, which covered power sector emissions from 2019 and 2020, successfully ended in December 2021 with a 99.5% compliance rate, i.e. allowances corresponding to 99.5% of the verified emissions were returned by the end of 2021. Allowances mostly traded at around CNY 40-60/t CO_2, with a weighted average price of CNY 42.85/t CO_2. However, the market has shown challenges of limited liquidity, with a cumulative trading volume of 179 million allowances for 2019 and 2020 verified emissions,

[10] Only heat generation from combined heat and power units is covered; heating-only plants are not covered by China’s national ETS.
[11] A company is included if it remains in operation and owns power units with annual emissions over 26 000 t CO_2 in any year over the period of 2013-2019. The threshold for inclusion would be met by a coal-fired power unit of 6 MW running at 2018 average capacity factor.

representing around 4% of annually covered emissions and with the vast majority traded only in the month of December before the compliance deadline (China, MEE, 2022).

Table 1.1 Benchmark design for electricity generation for 2019 and 2020

Benchmark category	Technology type	CO_2 emissions benchmark for electricity generation (g CO_2/kWh)
Unconventional coal-fired units	Circulating fluidised bed (CFB)	1 146
Conventional coal-fired units at and below 300 MW	High-pressure Subcritical ≤ 300 MW Supercritical ≤ 300 MW	979
Conventional coal-fired units above 300 MW	Subcritical > 300 MW Supercritical > 300 MW Ultra-supercritical Coal with CCUS	877
Gas-fired units	Gas Gas with CCUS	392

Note: CCUS = carbon capture, utilisation and storage. The analysis made the assumption that coal- and gas-fired power units equipped with CCUS technology are subject to the same benchmarks as the large conventional coal and gas units.
Source: China, MEE, 2020.

China's ETS currently employs an intensity-based allowance allocation approach,[12] where emissions allowances – each representing the right to emit one tonne of CO_2 – are allocated to coal- and gas-fired power plants according to their output level (e.g. total MWh of electricity generated in 2019-2020) and predetermined emissions intensity benchmarks (in tonnes of CO_2/MWh for electricity and tonnes of CO_2/GJ for heat generation) for each fuel and type of plant. The current allowance allocation plan defines four benchmark categories, three for coal-fired and one for gas power plants (Table 1.1).

Coal- and gas-fired plants receive emissions allowances based on their actual electricity and heat generation,[13] multiplied by the CO_2 emissions intensity benchmarks specific to the plant's fuel, technology, and size (Table 1.1). Allowances are currently allocated to power plant operators for free (China, MEE, 2021a). ETS compliance requires that a plant returns the number of allowances corresponding to its verified emissions, which are calculated based on its fuel consumption and fuel emissions factor.

[12] An intensity-based ETS is often also termed a tradable performance standard (TPS).
[13] During a compliance period, entities first received free allowances based on a certain percentage of historical production, and allowances were later adjusted to reflect actual production of the covered year(s). For example, for the 2021 compliance period which covered emissions from 2019 and 2020, entities first received allowances based on 70% of coal- and gas-fired plants' production in 2018, which were later adjusted to 2019 and 2020 production levels.

The coverage and stringency of the four benchmarks are critical for the effective functioning of an intensity-based ETS. If a plant's emissions intensity is higher than its applicable benchmark (typically when the plant is less efficient than the benchmark implies), it will face an allowance deficit and will have to buy allowances to be compliant. Conversely, if its emissions intensity falls below (i.e. performs better than) the benchmark, the plant will have received more allowances than it would need to surrender for its verified emissions, and can sell or potentially bank the surplus for a future compliance period, providing a financial incentive for reducing emissions intensity. Rules on banking are yet to be specified. In China's national ETS, to limit the scheme's burden on gas plants, which have a much lower emissions intensity than coal plants, gas-fired power plants are currently exempt from the obligation to purchase allowances in case of deficit. As the ETS covers only coal- and gas-fired power plants, generation from non-fossil energy sources such as renewables and nuclear power plants do not receive any allowances and cannot act as a source of supply to the market.

Entities are allowed to use Chinese Certified Emissions Reduction (CCER) offset credits to meet compliance obligations for up to 5% of verified emissions. Rules for CCER projects have been under revision since 2017, with new rules expected in 2022. Eligible credits for national ETS currently concern CCER credits approved prior to March 2017 (China, MEE, 2021a, 2021b) (see Box 4.2 in Chapter 4 for further discussion on CCERs).

The intensity-based design thus controls overall emissions intensity by encouraging power plants to reduce their emissions intensity below the benchmark level while remaining flexible in the context of China's growth in energy demand and industrial production. Since the intensity-based approach does not set a predetermined cap on total emissions, as in cap-and-trade systems such as the EU ETS, total emissions covered by China's current ETS can still rise (Box 1.2).

Box 1.2 Tradable Performance Standards and Cap-and-Trade Schemes

The design of China's ETS differs substantially from many other emissions trading systems implemented around the world. While most jurisdictions opted for a cap-and-trade scheme, China adopted an intensity-based system that essentially functions as a tradable performance standard (TPS) (Goulder et al., 2020).

A cap-and-trade scheme determines a maximum amount of GHG emissions that covered sectors are allowed to emit in a specific time period, thus setting an absolute cap on emissions. This creates incentives for regulated emitters to reduce emissions where these are most cost-effective, allowing the market to find the cheapest way to meet the overall quantity of capped emissions. Examples for this ETS type are the EU ETS, California's cap-and-trade scheme and New Zealand's ETS. In contrast, a tradable performance standard sets a relative emissions reduction target. A performance standard defines the maximum amount of emissions allowed *per unit of output* of the regulated entities. Therefore, it is also called a rate- or intensity-based standard or, sometimes, intensity-based cap (Brookings Institute, 2015; IEA, 2020a).

While both scheme types are effective market-based climate policy instruments, the differences in target-setting have a crucial impact on the mechanisms of GHG emissions reductions. In contrast to a cap-and-trade, a TPS does not set an absolute target. This reduces the predictability of total emissions reductions. Further, in a cap-and-trade scheme, energy efficiency improvements and the switch to low-carbon energy sources can serve as means to reduce emissions and meet the target. The latter channel to reduce emissions is undermined in a TPS if the benchmarks cover only fossil-based generation sources, as the more output (e.g. electricity and heat) a fossil-based plant produces, the more allowances it could receive. This feature could help to address challenges in target-setting related to output uncertainty, in particular in a situation where there is strong growth in economic and industrial activities. However, it also implicitly subsidises benchmark-covered output and incentivises lower emissions producers (i.e. those performing better than the benchmark) to excessively expand activities (Goulder et al., 2020).

China's renewables policy

Renewables have been a key pillar in China's energy policies over the last two decades, motivated by considerations for energy security, air quality, industrial development and climate goals. Driven by continuous policy support, China has been the global engine of renewable capacity growth, responsible for over 40% of the world's new installations between 2011 and 2020 (IEA, 2021d). As China seeks to continuously expand renewables deployment, the country has been gradually adapting its policy strategy for supporting and integrating renewables in its power sector.

Renewables targets

Since 2006, the Renewable Energy Law has been the legal and policy foundation for the large-scale development of renewables. This law covers fundamental elements such as capacity targets, planning, incentives, pricing mechanisms and cost sharing. It has guided the formulation and promulgation of a series of Five-Year Plans (FYPs) on renewables development.

China has set capacity targets for various renewable electricity technologies in recent FYPs on Renewable Energy Development and FYPs on Power Sector Development. The FYPs on Renewable Energy Development also set out indicative generation targets for renewables. The 13th FYP on Renewable Energy Development (2016-2020) set targets for installed renewable capacity at 715 GW (including 40 GW pumped storage hydropower) and for renewables to reach 27% of total generation by 2020. Both targets were overachieved with more than 930 GW of installed capacity and a generation share of 29.5%. China's 14th FYP for a Modern Energy System and recent communication on the 14th FYP on Renewables Energy Development (2021-2025) renew ambitions on renewables deployment while putting greater focus on consumption targets and renewables integration. They indicate that renewables will meet the majority of the growth in energy and electricity consumption. By 2025, the share of non-fossil electricity generation (including from renewables and nuclear) is stipulated to reach around 39% (China, NDRC and NEA, 2022b). Renewable electricity consumption is set to account for 33% of total electricity consumption, with 18% coming from non-hydro renewables (China, NEA, 2022). Along with renewable targets, China has set targets to increase flexibility sources and demand-side response capacity to support a higher share of variable renewables in the electricity system (China, NDRC and NEA, 2022b). The country has strengthened policy planning on storage development, targeting 30 GW of new energy storage capacity (mainly battery systems) by 2025 (China, NDRC and NEA, 2021b) and 120 GW of total pumped hydro storage by 2030 (China, NEA, 2021b). While grid companies are the main actors responsible for ensuring renewables integration, generators are encouraged to develop or contract storage and balancing capacities in order to be able to increase the renewable capacity connected to the grid (China, NDRC and NEA, 2021c).

Feed-in Tariff

Rapid renewable capacity expansion in China has mainly been driven by the feed-in tariffs (FIT) introduced in the late 2000s, which provide financial incentives to non-hydro renewables. The FIT scheme provides a 20-year contract to qualified projects with fixed FIT rates that are established on the basis of the type of renewable technology and resource level at the project location. While the scheme has successfully promoted renewables growth, challenges have emerged as installation has far exceeded initial expectations. These include national subsidy deficit and renewables integration difficulties.

During the 13th FYP period (2016-2020), China revised its FIT rates down and phased out FIT subsidies from the central government for new wind and solar projects by the end of 2020 (China, NDRC, 2021b).[14] The country gradually transitioned away from the scheme to other support instruments, including competitive auctioning, voluntary green certificate trading and renewable portfolio standards (RPS). These aim to make renewables more cost-competitive and reach "grid-parity" with other sources of generation, promote better integration and reduce subsidy burden on government funding.

Renewable portfolio standards

In 2019, China introduced a renewable portfolio standards (RPS) scheme to promote sustainable development and better integration of renewables, marking an important shift from capacity targets (in MW) to generation/consumption targets (in MWh), which provide stronger incentives for installed capacity to effectively deliver renewable electricity and minimise curtailment. The RPS scheme sets annual targets on shares of total renewables and non-hydro renewables in electricity consumption by province, taking into consideration provincial renewable capacities, interprovincial electricity exchanges and China's five-year target for the share of non-fossil fuels in primary energy consumption. For instance, in support of the 13th FYP target for non-fossil fuels to reach 15% of total primary energy consumption, the RPS targets by province for 2020 were set to increase the share of renewables in national electricity consumption to over 28% and the share of non-hydro renewables (mainly wind and solar) to nearly 11% (China, NDRC and NEA, 2020). Under the RPS scheme, two types of obligated parties need to fulfil the targeted renewables and non-hydro renewables shares in their electricity sales or consumption: i) grid, distribution and retail companies which directly sell electricity to end-consumers, and ii) large consumers that purchase electricity from the wholesale market and entities with captive power plants. Obligated parties can fulfil the targets by generating their own renewable electricity, procuring it via the grid or directly from a renewable electricity generator (e.g. via the recently piloted green power trading), a bilateral agreement with those exceeding their RPS quota, or by purchasing green certificates (China, NDRC and NEA, 2019) (Box 1.3). Provincial governments are responsible for implementing the RPS obligations, and grid companies assume a co-ordination role.

[14] China phased out its FIT scheme and competitive auctions for new onshore wind, utility-scale solar PV and commercial and industrial distributed PV projects. Offshore wind and concentrated solar power projects no longer benefit from FITs but may be awarded in provincial competitive auctions. Residential distributed PV projects benefit from an extension of the FIT scheme.

Box 1.3 RPS companion policies: Green certificates and green power trading

China implemented a voluntary green certificates scheme in 2017 to enhance renewables integration and increase financial flows to renewables (China, NDRC, MOF and NEA, 2017). In 2021, it began to change this scheme into a complementary policy to the mandatory RPS scheme (China, MOF, NDRC and NEA, 2020).

Tradable green (or renewable energy) certificates systems are schemes that establish a market for the “greenness”, i.e. the non-energy environmental attributes of renewable energy, with the aim to support the eligible technologies. A green certificate accredits a certain amount of renewable energy and can be traded on the certificate market to reward its generator or owner. At the same time, green certificate systems provide a mechanism for tracking issuance and ownership of certificates to substantiate claims of use of renewable energy. Around the world, green certificate schemes often accompany RPS policies to allow for accurate tracking of RPS compliance and reduce compliance costs by providing obligated parties the flexibility to meet target by certificate purchase.

In China’s green certificate scheme, one green certificate accredits 1 MWh of non-hydro renewable electricity and can be traded to provide renewable generators an additional revenue to electricity sales, with large-scale onshore wind and solar PV projects currently being eligible. Since its launch, the green certificates scheme has co-existed with the FIT scheme: renewable generators eligible for FITs can issue green certificates but sales of the certificates entail foregoing the FIT, and the certificate price is capped by the subsidy under the FIT scheme (i.e. the relevant FIT rate minus coal-fired power benchmark price). Since selling green certificates meant giving up FIT subsidies for generators, FIT rates had a strong influence on green certificates’ price: between July 2017 and December 2020, certificates for onshore wind and solar projects that were eligible for FITs traded on average at around CNY 175 and CNY 670 respectively – mirroring the significantly higher FIT for solar. Transactions were low, with less than 1% of listed certificates (and around 0.15% of issued certificates) being sold, as buyers had no obligation to purchase green certificates under the voluntary scheme.

As China transitions from FITs to the RPS, the green certificate scheme is being reformed to support RPS compliance and the market has been evolving. The certificate pricing trend is already changing: while certificates from existing projects that have rights to FITs over the coming years continued to be sold at similar prices as before, the green certificates from more recent wind and solar projects, which are not eligible for FITs, were on average traded at much lower prices at around CNY 50 in 2021. By the end of 2021, non-FIT eligible projects accounted for nearly 90% of cumulative green certificates sold. Trading volume has increased with rising demand for certificates as the scheme is increasingly identified as a channel to meet RPS obligations. The cumulative number of certificates sold rose to 15 times that in December 2020 and accounted for 9% of listed certificates (China green certificate trading platform, 2021).

China is also co-ordinating the scheme with green power trading. Piloted in 2021, green power trading allows renewable electricity (currently wind and solar PV) to be traded as a distinct product within the framework of bilateral mid- and long-term forward contracts between electricity generators and consumers, allowing for a green premium. The first green power contracts produced a premium of CNY 0.030-0.050/kWh, similar to the average price of non-FIT eligible green certificates. Purchasers of green power receive a certification of their green electricity consumption, which is in the process of being co-ordinated with the green certificate scheme (China, NDRC, 2021c; Xinhua, 2021a, 2021b).

In February 2021, the NEA issued a consultation draft on RPS targets for 2021 and indicative targets for 2022-2030, envisaging a national target for renewables to reach 40% of total electricity consumption and non-hydro renewables to reach 25.9% by 2030, with the aim to secure China’s 2030 targets of 25% non-fossil fuel share in total primary energy consumption and 1 200 GW of wind and solar capacity (China, NEA, 2021a). The final policy document released in May 2021 set provincial targets for 2021 and indicative targets for 2022, and specified that RPS targets will be set annually with final targets for the current year and indicative targets for the next year (China, NDRC and NEA, 2021d).

Interaction between and integration of RPS and ETS

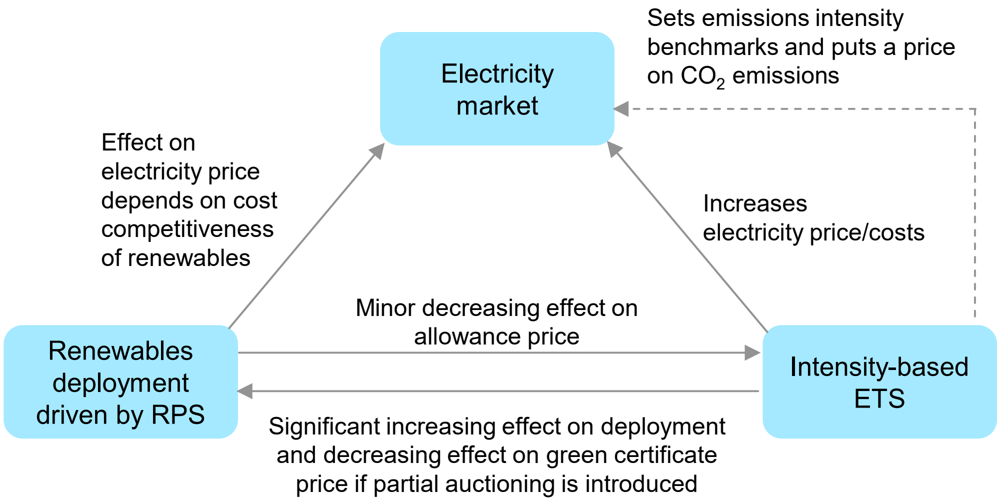
While renewable support policies such as an RPS and an ETS are each designed to target one primary objective, they have significant potential to either complement and support each other, or to interfere with each other in counterproductive ways. An ETS is a climate policy instrument that uses market forces to reduce carbon emissions where it costs least. While an ETS can effectively drive decarbonisation especially through operational changes, energy efficiency measures, fuel switching and the promotion of innovative low-carbon technologies (Aldy and Stavins, 2012), it is often complemented with renewable support policies. These complementary policies aim to further incentivise innovation in and de-risking of emerging low-carbon technologies, lower the long-term cost of the clean energy transition, improve industrial competitiveness and ensure security of supply.

There are noteworthy potential overlaps between an RPS policy and an ETS. In the electricity sector, an RPS policy creates obligations to increase the share of renewables in the power consumption mix while an ETS aims to reduce power-related emissions including through fuel switching to lower-carbon sources. The RPS' companion green certificate scheme and the ETS both aim to set price incentives to make power supply from carbon-intensive generators, such as unabated coal power, less attractive relative to lower-carbon power sources. In the short run, the combination of both could increase electricity prices – although less so in a regulated electricity market. The exact extent of this, however, very much depends on policy design specificities, the power generation mix, electricity market design and the pace of cost reduction of alternative lower-carbon generation sources.

Interaction of RPS with intensity-based ETS

Interaction between an RPS scheme and an intensity-based ETS focusing on fossil-based generation may be limited. In this case, renewables deployment driven by the RPS is unlikely to significantly reduce the demand for CO_2 emissions reductions in the ETS, as the demand for allowances – as well as the need for decarbonisation – is heavily driven by the performance of coal and gas power against their respective benchmarks. Renewables cannot act as a source of allowance supply in this system and therefore would have only a minor effect on decreasing the allowance price. Renewables are also unlikely to receive a significant incentive from the system if all allowances are allocated to fossil-based generators for free. The intensity-based ETS could, however, have a stronger role in incentivising renewables deployment if partial auctioning is implemented, as this decreases the cost competitiveness of fossil-based generation further in relation to renewables. In turn, this additional incentive for renewables deployment through the ETS could lead to a significant decrease in the premium to green power or the price of green certificates that could be used to fulfil the RPS obligations.

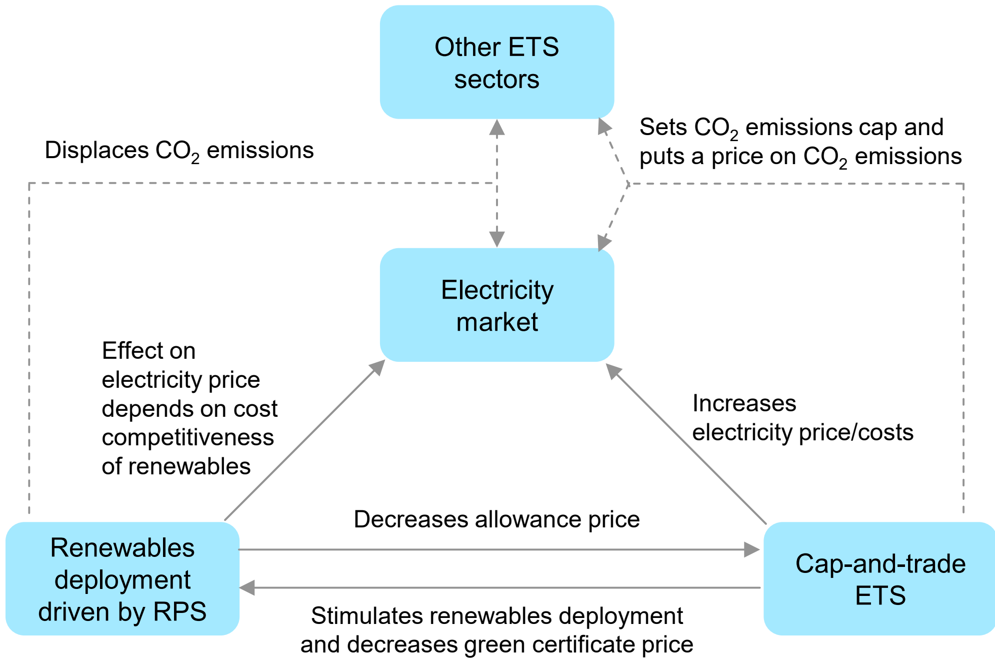
Figure 1.2 Schematic illustration of interaction between an RPS and an intensity-based ETS focusing on fossil-based generation



Interaction of RPS with cap-and-trade ETS

Interactions between RPS and a cap-and-trade ETS are likely to be stronger compared with an intensity-based ETS, and could impact policy effectiveness in the absence of sufficient co-ordination. For instance, a higher share of renewable electricity generation achieved through an RPS scheme reduces electricity-related emissions, which decreases demand for emission allowances in a cap-and-trade ETS where allowance supply is set by a predetermined cap. This could, in turn, drive down the allowance price and decrease the effectiveness of the ETS. This effect is likely more pronounced in a cap-and-trade ETS if the cap does not take into account the expected renewables deployment incentivised by an RPS. In addition, in a cap-and-trade ETS that covers multiple sectors such as industry and electricity, the ETS cap sets the total emissions that covered sectors are allowed to emit. In such a design, emissions reductions in the electricity sector through the RPS could leave more room for industry to emit without breaching the overall cap of the ETS if, in setting the cap, the policy maker does not anticipate such emissions reductions or adjusts the cap afterwards – a so-called *displacement effect* (Figure 1.3) (Lehmann and Gawel, 2013). This could again lead to lower allowance prices and a reduced incentive for further decarbonisation in sectors covered by the ETS. On the other hand, a cap-and-trade ETS would increase the relative competitiveness of renewables and encourage their deployment by setting a financial disincentive for fossil-based generation through the carbon price, which would contribute to meeting the RPS target but would likely decrease the green certificate price accompanying the RPS.

Figure 1.3 Schematic illustration of interaction between an RPS and a cap-and-trade ETS



Source: IEA, adapted from Van den Bergh, Delarue and D'haeseleer (2013).

Therefore, it is important that policy makers assess the interaction channels and impacts when designing energy and climate policies in advance. This can be facilitated through the institutionalisation of policy co-ordination across all relevant Ministries in addition to NDRC's overarching co-ordination role, and help ensure that a climate and energy policy instrument mix achieves its multiple policy objectives more effectively and at a lower cost, which is important for the social acceptability of clean energy transitions. In addition, introducing flexibility mechanisms such as a Market Stability Reserve[15] in an ETS, or price corridors in an ETS and a green certificate scheme can also accommodate deviations in the initially expected emissions reductions and demand for allowances by adjusting supply and demand.

[15] The EU ETS' Market Stability Reserve (MSR) is a good example of such a flexibility mechanism that automatically adds or removes allowances from the ETS if the volume of allowances in circulation is lower or higher than the pre-defined thresholds.

Chapter 2. Key features of the model and scenario design

This report relies on quantitative output from scenario simulations designed to understand the effects of, and evaluate the interactions between RPS and ETS policies in China's power sector. This chapter presents key features of the model and explains how it incorporates the RPS and ETS. It further gives an overview of the five scenarios assessed in this report: the first two scenarios include a counterfactual RPS Scenario, as well as a current policy scenario that incorporates RPS and a moderate ETS based on the design implemented in China today. An additional three policy scenarios explore ways to accelerate the alignment of China's power sector emissions trajectory with the country's stated carbon neutrality target by strengthening the ETS design.

Model design

To analyse how China's ETS affects the country's power sector, this report uses a market-based power system model that minimises total power system costs, and includes both endogenous capacity and transmission line expansion and dispatch modules. The system cost optimisation takes into account annualised capital expenditure as well as variable and fixed operating and maintenance costs of electricity generation, transmission and balancing costs, and costs for plant retrofits, subject to policy constraints and resource variability such as geographical distribution of renewable resources and fossil fuel costs. CO_2 costs or gains resulting from the ETS policy are considered to be integrated in plant operating and investment decisions and are included in the model's cost optimisation.

The model uses 2015 as the base year and assesses potential ETS impacts in five-year increments up to 2035. The simulation for 2020 has been strongly calibrated based on 2020 statistics. Initial national and provincial capacity and generation mixes are based on data from the China Electricity Council (CEC).

The modelling exercise incorporates some key assumptions for power sector development, technology costs and policy trends, to simulate the effects of key policies on China's power system, and their potential contribution to achieving China's climate and energy objectives. Electricity demand for 2015 and 2020 are based on CEC data, and future electricity demand is aligned with the IEA's Announced Pledges Scenario (IEA, 2021b). Taking into account China's ongoing power market reform, including the aim to build nation-wide electricity markets by 2025, the model assumes partly planned dispatch in 2020 and economic dispatch from 2025 onwards,[16] while allowing for interprovincial trade up to the limit of transmission capacity, and optimises capacity and generation mixes accordingly. Minimum operating hours (2 500 hours per year) are assumed for gas-fired plants to reflect the political incentives for gas-fired power generation. Assumptions on electricity demand growth, exogenous technology cost evolutions and renewables policy framework (detailed in the Modelling of RPS Policy section below) are kept identical across all scenarios in this report. The Annex includes a more detailed description of the Renewable Electricity Planning and Operation (REPO) model and key inputs for capacity and generation mix, cost assumptions and emission factors.

It is noteworthy that cost optimisation models such as the REPO model face restrictions in representing the power sector's complex mechanisms and cannot fully capture all uncertainties regarding future developments. The REPO model seeks to minimise total power system costs and therefore scales least-costly technologies in a finite time horizon. It does so, however, within the assumptions and constraints mentioned in the Annex. The outputs should therefore be viewed with those modelling limitations in mind.

Modelling of RPS Policy

China's RPS policy sets targets for the shares of all renewables and non-hydro renewables in total electricity consumption. The RPS policy is modelled by a generation constraint where the share of electricity from non-hydro renewables in the total demand should be no less than the required target. This analysis assumes non-hydro renewables share targets to be 18.6% by 2025, 25.9% by 2030 and 36% by 2035, based on NEA's consultation draft of indicative RPS targets up to 2030 (China, NEA, 2021a) and assuming a moderate acceleration of targets up to 2035. The model does not directly set a constraint on the total renewables share, as the dynamic for hydropower and non-hydro renewables differs considerably. Instead, the model includes assumptions on hydropower capacity development in line with policy planning and resource availability. The model does not make assumptions on provincial renewables capacity targets and allows for interprovincial power trading in fulfilling RPS obligations.

Under the RPS target constraint, the model also produces a so-called green electricity premium, which reflects the level of financial incentive needed for the system to increase non-hydro renewables generation to meet the RPS target. It is a premium awarded to non-hydro renewables to outcompete other sources,

[16] Planned dispatch involves administratively assigned operating hours. In the case of China, this has traditionally been the provision of an operating hours range per technology to generators by the administration. Economic dispatch is the short-term determination of the optimal electricity output to meet the required electricity demand based on a merit order curve which determines the lowest marginal cost to meet the system load.

including existing fossil-based generation sources. The green electricity premium is used to explore, first, the potential financial incentive required to achieve a power system with a higher share of renewables, and second, the interactions between ETS and RPS policies. For the latter, it is an indicator of how the ETS can contribute to providing financial incentives to non-hydro renewables and how it might impact renewables support schemes such as the green certificate and green power trading markets.

The value of the green electricity premium in the model is mainly influenced by generation costs of non-hydro renewables vis-à-vis other sources. It is also partially influenced by system integration costs, such as for storage and balancing in order to integrate a higher share of variable renewable energy. Its value can therefore be positive even if the cost of renewables deployment on average reaches parity with other sources. This is, first, because renewables resources vary geographically and a higher share of renewables may require deployment in regions with less resources and higher costs, and second, because integration costs could rise as a higher share of renewables leads to more integration needs.

Modelling of the ETS

The ETS is modelled through an emissions constraint function whereby total verified CO_2 emissions must remain below the total CO_2 allowances allocated under the ETS. Depending on the scenario, the ETS allowance allocation either uses an intensity-based approach, with the number of allowances based on annual electricity generation and technology-specific benchmarks, or follows a cap-and-trade approach with a defined emissions trajectory. Verified CO_2 emissions represent allowances that must be returned for compliance, and they are calculated by multiplying fuel consumption with the CO_2 fuel factor.[17] Analysis is conducted at the unit level, and the modelling assumes that companies covered by the ETS perform cost optimisation for operational and investment decisions within their portfolio when complying with the system. The main levers for emissions reductions include (i) efficiency improvement in fossil-based generation, such as through technical efficiency improvements or retrofits and shifting generation from less to more efficient plants, (ii) deployment of CCUS technology on fossil-based power plants, (iii) switching from coal-fired to gas-fired generation, and (iv) switching from fossil-based generation to non-fossil sources. Demand reduction is not analysed as a main lever in this modelling exercise, as electricity demand is an exogenous assumption and remains identical across scenarios. The

[17] This report applies an average fuel factor for coal of 101.65 kg CO_2/GJ for the analysed period, taking into account the use of a high default factor in case of non-monitoring according to China's ETS MRV rules. In reality an increase in monitoring of the CO_2 fuel factor by units could reduce the average fuel factor for verified emissions to e.g. 95 kg CO_2/GJ (factor for "other bituminous coal", the dominant fuel source in China's coal power sector). In this case, benchmark tightening rates will need to be further increased accordingly to achieve the same tightening effect as presented in this report.

allowance price is an output of the model. It reflects the marginal cost of emissions abatement that minimises total system costs while meeting the allocated number of allowances.

For scenarios including an intensity-based ETS, the analysis assumed a set of benchmark values, in accordance with the four benchmark categories in China's ETS allowance allocation plan for 2019-2020: unconventional coal-fired units, conventional coal-fired units at and below 300 MW, conventional coal-fired units above 300 MW and gas-fired power units. The benchmark values for 2020 are shown in Table 1.1 as presented in Chapter 1. Benchmark evolutions post 2020 vary across scenarios and are detailed in the section below.

As in China's current ETS allowance allocation plan, gas-fired units with an allowance deficit are not required to purchase allowances for compliance, to reflect political incentives for fuel switching to gas. There is no provision for allowance banking (i.e. the use of surplus allowances in a future compliance period) as the rules on banking are yet to be specified. Chinese Certified Emissions Reduction (CCER) offsets as a source to meet allowance obligations have not been part of the modelling.

Scenario design

Current policy and counterfactual scenario

The **RPS-ETS Scenario** is based on the currently planned development of China's climate and energy policy framework for the power sector. In order to evaluate the role of the ETS in the power sector transition, it is compared to a hypothetical counterfactual scenario (the **RPS Scenario**). The two scenarios are developed to evaluate the implications of China's ETS with a free intensity-based allocation design, and its combined effect with the RPS policy. Key assumptions of the two scenarios are outlined below (Table 2.1), and their results are discussed in Chapter 3:

- **RPS Scenario:** a counterfactual scenario with the current RPS policy set-up but with no emissions control or carbon pricing policy. It assumes a target for the share of non-hydro renewables of 25.9% by 2030 and 36% by 2035.
- **RPS-ETS Scenario:** a current policy scenario with the same RPS policy assumptions and an intensity-based ETS with free allocation, as currently implemented in China. This scenario assesses the ETS policy effects and interactions with RPS policies in the power sector. It assumes that ETS benchmarks for all coal-fired units are moderately tightened over time: a 3% benchmark tightening rate is assumed for the five-year period to 2025, following a trend comparable with the historical efficiency improvement of coal plants over the last five years, and doubled thereafter to reflect an increase in policy stringency.

Table 2.1 Design of RPS and RPS-ETS Scenarios

Scenario	Policy area	Policy instrument	Design evolution			
				2025	***2030***	***2035***
RPS Scenario	Renewables support	RPS	Non-hydro RPS target	18.6%	25.9%	36.0%
	Emissions control	No specific instrument	-/-			
RPS-ETS Scenario	Renewables support	RPS	Non-hydro RPS target	18.6%	25.9%	36.0%
	Emissions control	Emissions trading system	Allowance allocation	Intensity-based		
				Free allocation		
			Benchmark tightening at the same rate for all coal units' benchmarks over five-year period	-3%	-6%	-6%
			Constant benchmark for gas-fired units			

Note: This report applies an average fuel factor for coal of 101.65 kg CO_2/GJ for the analysed period, taking into account the use of a high default factor in case of non-monitoring according to China's ETS MRV rules. In reality an increase in monitoring of the CO_2 fuel factor by units could reduce the average fuel factor for verified emissions to e.g. 95 kg CO_2/GJ (factor for "other bituminous coal", the dominant fuel source in China's coal power sector). In this case, benchmark tightening rates will need to be further increased accordingly to achieve the same tightening effect.

Enhanced ETS Scenarios

In 2020, China announced that it aims to have CO_2 emissions peak before 2030 and become carbon neutral before 2060. To achieve these targets, the country's power sector needs to undergo a deep transformation. Therefore, this report develops three possible policy pathways with strengthened ETS designs that can accelerate the alignment of the electricity sector's emissions trajectory with China's target for carbon neutrality before 2060.

All three Enhanced ETS (ETS+) Scenarios are designed to achieve an emissions trajectory that is aligned with China's stated carbon peaking and carbon neutrality goals. The ETS+ Scenarios use the emissions trajectory of the IEA's Announced Pledges Scenario (APS) in *An energy sector roadmap to carbon neutrality in China* and in the *World Energy Outlook 2021* (IEA, 2021b) as input to define the necessary ETS stringency in the three scenarios.[18]

While keeping the same RPS policy assumptions as in the **RPS** and the **RPS-ETS** Scenarios, the three ETS+ Scenarios each strengthen the ETS via a different

[18] There is no single pathway for energy sector emissions consistent with China's stated goals of achieving a peak in CO_2 emissions before 2030 and carbon neutrality before 2060. The Announced Pledges Scenario (APS) presents one plausible pathway to carbon neutrality in China's energy sector in line with the country's stated goals. The IEA's report "An energy sector roadmap to carbon neutrality in China" also explores an Accelerated Transition Scenario (ATS) to assess the opportunities for and implications of a faster transition through enhanced climate policy ambitions and efforts to 2030.

design evolution after 2025 (Table 2.2) to achieve the same intended emissions trajectory:

- **ETS+BM Scenario:** a scenario with a more stringent intensity-based ETS through significant tightening of the allowance allocation benchmarks for coal-based plants. In contrast to the RPS-ETS Scenario, the ETS+BM models higher coal benchmark tightening rates from 2025 onwards: the five-year tightening rate is doubled to 12% in the period 2025-2030 and increases again to 22% in 2030-3035.
- **ETS+Auction Scenario:** a scenario that introduces partial auctioning of emissions allowances in the intensity-based ETS. This scenario relies on the same intensity-based ETS and benchmark tightening rates as the RPS-ETS Scenario but assumes fully free allowance allocation until 2025 with partial auctioning introduced thereafter, i.e. for a given production, only part of the allowances determined by the applicable benchmarks are allocated for free while others are supplied to the market via auctioning. By 2030, 17.5% of the allowances are auctioned, and by 2035 this share rises to 23.5%.
- **ETS+Cap Scenario:** a scenario that transitions the intensity-based ETS to a cap-and-trade ETS with an absolute emissions cap that decreases over time. Until 2025, this scenario assumes an intensity-based ETS with the same benchmark tightening rate as the RPS-ETS Scenario. After 2025, the ETS is transformed into a cap-and-trade scheme with free allowance allocation. The allowance cap is set at 11% lower than 2020 emissions for 2030 (3.99 Gt CO_2) and then decreases further to about 38% lower than 2020 in 2035 (2.78 Gt CO_2).

Table 2.2 Design of different Enhanced ETS Scenarios

Scenario	RPS share target		Emissions Trading System (ETS)			
	2030	2035		2025	2030	2035
Current Policy Scenario						
RPS-ETS	25.9%	36.0%	Coal benchmarks tightening rate (over five-year period)	-3%	-6%	-6%
Enhanced ETS (ETS+) Scenarios						
ETS+BM	25.9%	36.0%	Coal benchmarks tightening rate (over five-year period)	-3%	-12%	-22%
ETS+Auction	25.9%	36.0%	Coal benchmarks tightening rate (over five-year period)	-3%	-6%	-6%
			Share of allowance auctioning	-/-	17.5%	23.5%
ETS+Cap	25.9%	36.0%	Coal benchmarks tightening rate (over five-year period)	-3%	-/-	-/-
			Allowance allocation	Intensity-based	Cap-and-trade	Cap-and-trade
			Cap reduction (relative to 2020 emissions)	-/-	-11%	-38%

Note: This report applies an average fuel factor for coal of 101.65 kg CO_2/GJ for the analysed period, taking into account the use of a high default factor in case of non-monitoring according to China's ETS MRV rules. In reality an increase in monitoring of the CO_2 fuel factor by units could reduce the average fuel factor for verified emissions to e.g. 95 kg CO_2/GJ (factor for "other bituminous coal", the dominant fuel source in China's coal power sector). In this case, benchmark tightening rates will need to be further increased accordingly to achieve the same tightening effect.

The benchmark reduction rates of the different scenario designs translate into significant reductions of the absolute benchmark values over time. In the period of 2020-2035, in the RPS-ETS and ETS+Auction Scenarios, coal benchmarks are reduced by a total of 14% while the ETS+BM Scenario experiences an overall reduction of 33%. Since only the benchmarks of coal technologies are reduced, there is no decrease in the gas benchmark. Table 2.3 summarises the resulting absolute benchmark values.

Table 2.3 Assumptions on benchmark values for 2020-2035

	CO_2 emissions benchmark for electricity generation (g CO_2/kWh)					
Benchmark category	2020	2025	2030		2035	
			RPS-ETS, ETS+Auction	ETS+BM	RPS-ETS, ETS+Auction	ETS+BM
Unconventional coal-fired units	1146	1112	1045	982	982	765
Conventional coal-fired units at and below 300 MW	979	950	893	839	839	653
Conventional coal-fired units above 300 MW	877	851	800	750	750	585
Gas-fired units	392					

Notes: The analysis made the assumption that coal- and gas-fired power units equipped with CCUS technology are subject to the same benchmarks as large conventional coal and gas units. This report applies an average fuel factor for coal of 101.65 kg CO_2/GJ for the analysed period, taking into account the use of a high default factor in case of non-monitoring according to China's ETS MRV rules. In reality an increase in monitoring of the CO_2 fuel factor by units could reduce the average fuel factor for verified emissions to e.g. 95 kg CO_2/GJ (factor for "other bituminous coal", the dominant fuel source in China's coal power sector). In this case, benchmark tightening rates will need to be further increased accordingly to achieve the same tightening effect.

Chapter 3. The current policy mix – RPS and ETS

Based on the power sector modelling for 2020 to 2035 described in Chapter 2 and in the Annex, this chapter analyses two policy scenarios to explore the potential effects on China's power sector of i) a successful RPS policy, and ii) an RPS policy along with an intensity-based ETS with a moderate benchmark tightening trajectory. The analysis presented provides insights on the mechanism through which the two policies drive power sector decarbonisation, as well as their interactions.

Results of the RPS Scenario

The RPS Scenario – the counterfactual scenario against which the role of the ETS is evaluated – considers only power sector reforms such as economic dispatch and the RPS policy targeting a higher share of non-hydro renewables, but no policies to control CO_2 emissions. This section illustrates the impacts of such a scenario on the main power generation sources.

Successfully meeting the RPS targets of a 26% share for non-hydro renewables in the electricity consumption mix by 2030 and 36% by 2035 could help China's CO_2 emissions from the electricity sector peak before 2030 and moderately decline thereafter. In the RPS Scenario, despite continuous growth in electricity demand, emissions increase to 6% above 2020 levels in 2025 before falling to 3% above in 2030 and then decreasing to 7% below 2020 emissions levels – or 4.2 Gt – by 2035 (Figure 3.1).[19]

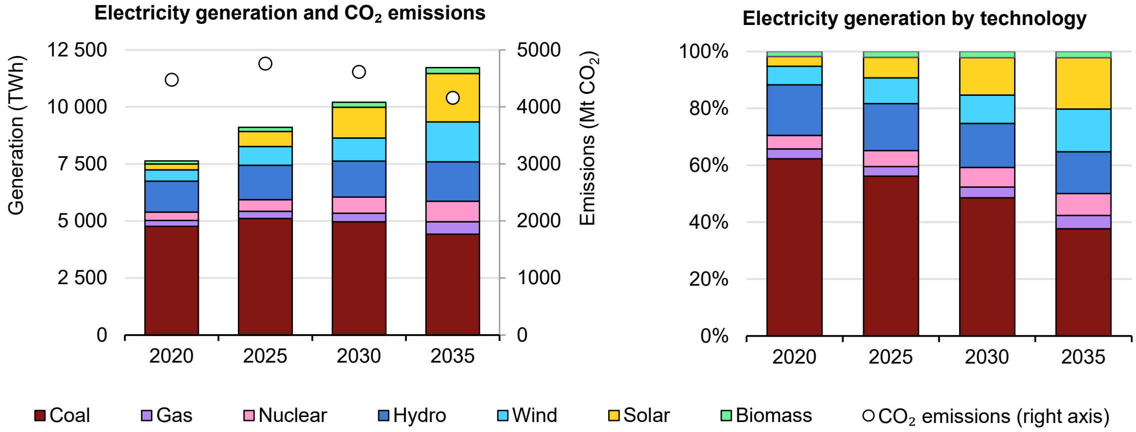
Compared to 2020, China's electricity demand is expected to expand by more than 50% by 2035. While in the past strong demand growth has led to higher generation, especially from unabated coal-fired power plants, this trend could be overturned in the course of the 2020s with increasing cost-effectiveness of renewables and successful implementation of RPS consumption share targets.

[19] The IEA and China's estimates for electricity sector emissions differ due to methodological differences, including how power sector emissions are attributed between heat and electricity generation of co-generation plants, and the emissions factors used for fossil fuel sub-categories. For the purpose of this report and to evaluate country-specific policy impacts, electricity sector emissions are estimated with China's methodology and are therefore lower than the IEA's estimate of around 4.8 Gt for China's emissions from electricity generation in 2020 (see Annex A for more information).

Impact on renewables

Under the RPS Scenario, renewables growth can meet over 60% of additional demand already in 2020-2025. After 2030, it exceeds demand growth in order to make up for the gradual phase-down of unabated fossil fuel-based generation. In total, from 2020 to 2035, renewables can meet about 90% of additional electricity demand.

Figure 3.1 Electricity generation and CO_2 emissions in the RPS Scenario, 2020-2035



The share of renewables in total electricity generation increases from almost 30% in 2020 to 41% in 2030 and 50% in 2035. Renewables generation nearly doubles to about 4 200 TWh from 2020 to 2030, reaching 5 800 TWh in 2035. Solar PV experiences the largest expansion, growing fivefold between 2020 and 2030 to over 1 300 TWh and 13% of electricity generation, and reaching 2 100 TWh (18% of total generation) in 2035 – in the course overtaking hydropower as the largest renewable electricity source. Wind production doubles between 2020 and 2030, and expands even more rapidly after 2030. This is to complement a higher share of solar PV for grid balancing purposes, and because further solar PV deployment becomes more expensive relative to wind power as the cheapest sources will already have been developed. In 2035, wind generation reaches 1 750 TWh, accounting for 15% of total generation. Hydropower generation grows moderately to 2035 – up 28% compared to 2020 – but its share in electricity generation falls from 18% to 15%.

In terms of capacity, installed renewables capacity nearly doubles to 1 850 GW in 2030, with wind and solar capacity reaching more than 1 300 GW, exceeding the target of 1 200 GW in China's updated NDC. By 2035, renewables capacity further grows to 2 600 GW – of which 2 000 GW will be wind and solar capacity – nearly four times the capacity in 2020.

In the RPS Scenario, the green electricity premium[20] for non-hydro renewables outputted by the model stands at CNY 0.030/kWh in 2025, indicating some financial support would still be needed to meet the RPS target share of renewables generation and related integration needs. However, this is at the lower end of the green premium observed in green power trading in 2021. As both renewables and storage technologies are expected to become increasingly cost-competitive (see the Annex for technology cost assumptions), the green electricity premium needed decreases to CNY 0.025/kWh in 2030 and to CNY 0.001/kWh in 2035 in the RPS Scenario. This suggests that by 2035 a 36% non-hydro renewables share could be achieved almost without incurring additional costs to the system – even including associated storage and balancing needs.

Impact on coal power

As strong renewable expansion meets an increasingly larger share of electricity demand growth, coal power generation experiences only a limited increase during the 2020s and peaks before 2030 in the RPS Scenario – a critical element for peaking China's electricity sector emissions before 2030. Coal's share in total generation steadily falls from 62% in 2020 to 38% by 2035 (Figure 3.1).

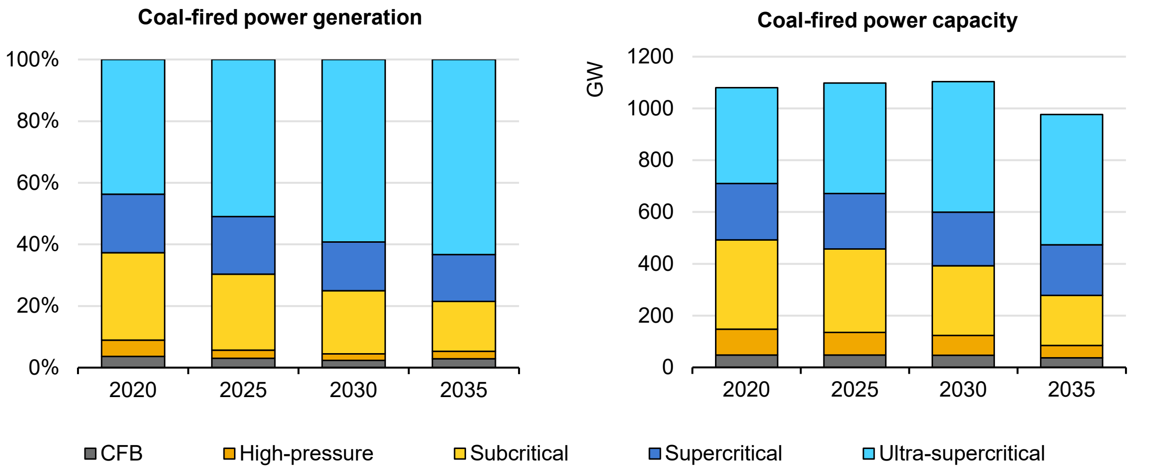
Coal power generation increases 7% from around 4 800 TWh in 2020 to 5 100 TWh in 2025 and then declines to below 5 000 TWh by 2030. It falls even more significantly to 4 400 TWh in 2035, which is about 7% lower than in 2020. The main driver is a more than 10% decline in coal power capacity from an average of around 1 100 GW in the 2020s to 980 GW in 2035 as older units reach the end of their lifetime. The average running hours of the remaining coal fleet increases slightly compared to 2020 due to a larger share of efficient ultra-supercritical coal plants, which maintain average running hours of 5 600 hours, while the running hours of other coal plants fall below 4 000 hours.

Within the coal fleet, the shift from less-efficient to more-efficient coal power continues, with ultra-supercritical units becoming increasingly dominant, and subcritical as well as high-pressure units declining in particular. However, if no additional policy incentives are provided to constrain coal power or further accelerate the development of low-carbon alternatives, nearly 140 GW of ultra-supercritical units could still be built in the decade to 2030. Total coal power capacity, nevertheless, remains roughly stable at around 1 100 GW as new additions and retirements are almost balanced. Further coal power capacity retirements of 130 GW could take place between 2030 and 2035 as typical end of lifetimes are reached. As a result, by 2035, ultra-supercritical units account for over 50% of coal capacity compared to one-third in 2020. Combined with higher

[20] For an explanation of the green electricity premium please see Box 1.3 in Chapter 1 and the section "Modelling of RPS Policy" in Chapter 2.

running hours than other less efficient units, ultra-supercritical units generate 63% of coal-fired power in 2035 (Figure 3.2). Average energy intensity of the coal fleet decreases only slowly over time at around -1% by 2025 compared to 2020, falling short of the -2% China targets for thermal power plants over this five-year period (China, NDRC and NEA, 2021a).[21] By 2035, the average energy intensity of the coal fleet decreases by less than -3% compared to 2020. In the RPS Scenario, CCUS technology is not yet cost-competitive and does not enter the power mix by 2035.

Figure 3.2 Coal power generation and capacity mix in the RPS Scenario, 2020-2035



Note: CFB = circulating fluidised bed.

Other power sector impacts

As the share of variable renewables in the power mix increases while coal gradually declines and hydropower is constrained by resource availability, dispatchable generation sources including nuclear and gas-fired plants play a more important role in the power mix. Both installed capacity and power generation from nuclear and gas units double in the RPS Scenario between 2020 and 2035 – albeit from low levels. The share of nuclear in the generation mix increases from 5% in 2020 to 8% in 2035, while the share of gas grows from 3% to 5%.

The rapid expansion of variable renewables also requires a strong development of storage capacity. Pumped storage hydro increases to 70 GW by 2025, surpassing the target (China, NEA, 2021b), and reaches 90 GW by 2030 with no further growth afterwards as battery storage becomes cost-competitive. Battery

[21] In order to assess the potential impact of the ETS policy on improving the efficiency of fossil-based power plants, this report and the underlying model do not pre-assume the achievement of thermal plant efficiency target.

storage capacity is set to increase from 3 GW in 2020 to 30 GW by 2025 driven by policy targets (China, NDRC and NEA, 2021b), and growing even faster especially after 2030 as deployment at scale brings cost down. Deployment of storage capacity plays a critical role in supporting the integration of a higher share of renewables and reducing the need for dispatchable fossil-based capacity to ensure supply security.

Results of the RPS-ETS Scenario

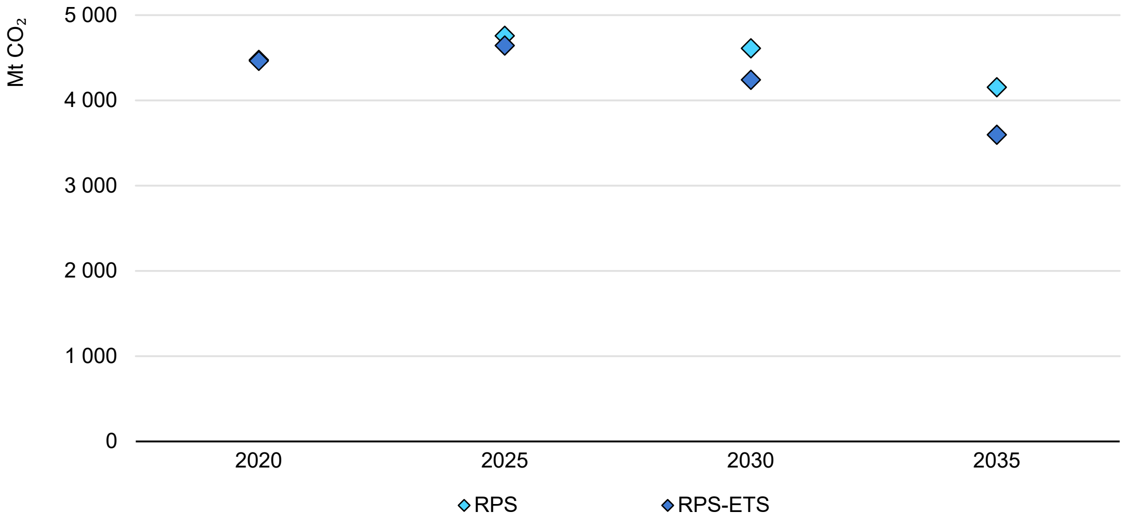
The RPS-ETS Scenario represents a current policy scenario with the same assumptions for RPS policy and exogenous technology cost evolutions as the RPS Scenario, and an intensity-based ETS with free allocation from 2020 onwards, as currently implemented in China. It also assumes a moderate tightening of allocation benchmarks over time (Table 2.1). This section illustrates the results of this scenario and compares them to the RPS Scenario to evaluate the effects of the ETS as well as its interaction with the RPS policy.

With increasingly stringent benchmarks, the ETS can deliver additional emissions reductions to the RPS policy and accelerate the decarbonisation of China's power sector. Using free and intensity-based allowance allocation, the ETS primarily drives the transformation of the coal power fleet towards higher efficiency and CCUS deployment, with limited impacts on renewables and other generation sources. The stringency of the benchmarks would only marginally impact the level of financial support needed to achieve a higher share of renewables.

Impact on CO_2 emissions and generation mix

In the RPS-ETS Scenario, the introduction of an ETS from 2020 allows electricity-related emissions to peak at a lower level than in the RPS Scenario. By 2030, CO_2 emissions from electricity generation are 8% lower than in the RPS Scenario, and fall to 5% below the 2020 level. Additional emissions reductions delivered by the ETS increase as benchmarks are tightened, leading electricity-related emissions to fall below 3.6 Gt CO_2 in 2035, nearly 20% below the 2020 level and 13% lower than in the RPS Scenario (Figure 3.3).

Figure 3.3 CO_2 emissions from electricity generation in the RPS and RPS-ETS Scenarios, 2020-2035



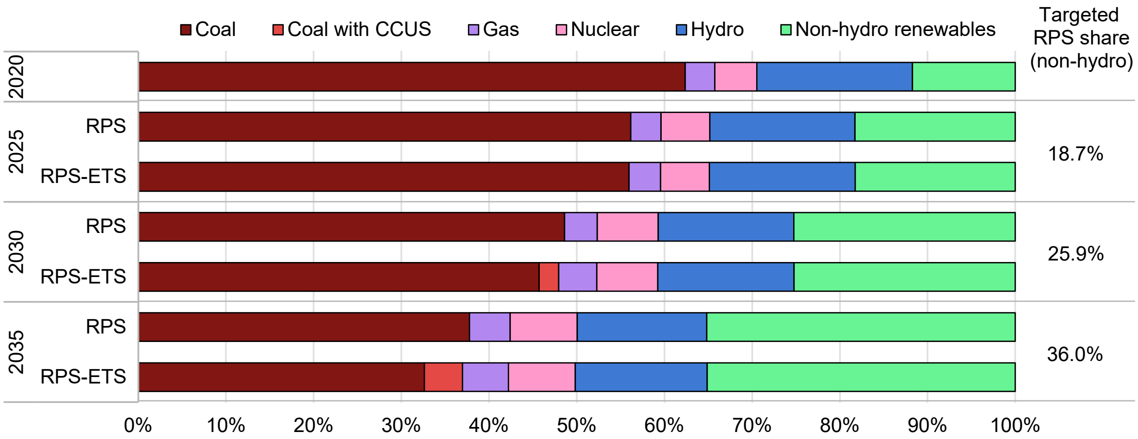
The introduction of an ETS delivers additional emissions reductions not by a higher share of renewables in the electricity generation mix, but by changes within the coal-fired power mix. Unabated coal power generation in the RPS-ETS Scenario develops in line with the RPS Scenario until 2025 – reaching 5 100 TWh – and afterwards falls to 3 800 TWh by 2035 (about 14% lower than in RPS Scenario) with a corresponding shift to coal power with CCUS. Before 2025, the ETS encourages efficiency retrofits and slightly accelerates the technology shift within the unabated coal fleet by decreasing the running hours of less efficient coal plants. Average energy intensity of the coal fleet decreases by 3% in the RPS-ETS Scenario (compared to around 1% in the RPS Scenario) and falls below the 300 gce/kWh (835 g CO_2/kWh)[22] target China set for thermal power plants by 2025. By 2030, average energy intensity of unabated coal falls to around 290 gce/kWh (807 g CO_2/kWh), though further efficiency improvements become increasingly costly and technically difficult.

The intensity-based ETS can thus serve as an effective instrument to support coal fleet efficiency improvements – but with increasingly stringent benchmarks it also drives the deployment of CCUS technology. While there is no CCUS deployment in the RPS Scenario, CCUS-equipped coal power plants could become cost-competitive in certain regions – also vis-à-vis renewables – due to the incentive effect of the intensity-based ETS design for coal with CCUS (see the following

[22] This assumes applying a CO_2 fuel factor of 95 kg CO_2/GJ (the factor for “other bituminous coal”) in the conversion. If applying the average fuel factor for coal of 101.65 kg CO_2/GJ used in this report’s modelling, the respective carbon intensities would be 894 g CO_2/kWh for 2025 and 864 g CO_2/kWh for 2030.

section "Impacts of CO_2 costs on technologies"). In the RPS-ETS Scenario, around 70 GW of CCUS-equipped coal plants are developed which generate around 510 TWh in 2035, accounting for 4% of total generation.[23] Gas power generation also increases by about 15% in 2035. Through the deployment of CCUS-equipped coal and increased gas power generation, the displacement of 600 TWh of unabated coal power generation is possible by 2035. However, the deployment of low-carbon sources remains unaffected, with generation from renewables and nuclear growing at the same pace in both scenarios (Figure 3.4).

Figure 3.4 Electricity generation by technology in the RPS and RPS-ETS Scenarios, 2020-2035



Impact of CO_2 costs on technologies

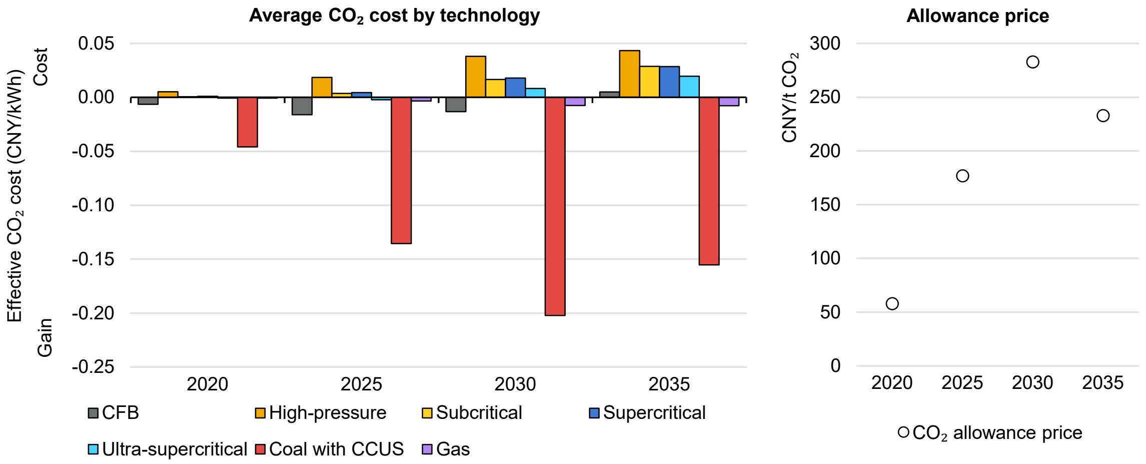
The CO_2 allowance price reflects the marginal abatement cost[24] that keeps emissions at the level that corresponds to the number of allowances allocated to emitters. In an intensity-based ETS, allowance allocation is not limited by a pre-set cap, but depends on production activities and emissions intensity benchmarks. As China's ETS covers coal- and gas-fired power with separate benchmarks, the allowance price primarily sends a signal to enable decarbonisation options that can reduce the emissions intensity of fossil-based generation sources in line with those benchmarks. Non-fossil generation, on the other hand, is not included in the benchmark categories and cannot act as a source of allowance supply. In the RPS-ETS Scenario, the allowance price rises from around CNY 60/t CO_2 in 2020 to CNY 280/t CO_2 in 2030 as the ETS shifts to drive CCUS deployment in addition

[23] Plant running hours are a result of the model's optimising system costs under economic dispatch and policy constraints (such as the RPS and ETS). A maximum 85% capacity factor is set for coal plants. As a result, the model produces higher average running hours for CCUS-equipped coal plants than for unabated coal plants.
[24] Abatement cost is the cost of reducing environmental externalities. The marginal abatement cost is the cost of reducing one more tonne of CO_2. It thus reflects the cost of reducing the emissions to a given level – in the context of China, to the number of allowances allocated to emitters covered by its ETS.

to encouraging relatively cheap improvements in coal fleet efficiency under increasingly tightened emissions intensity benchmarks. By 2035, the allowance price then decreases to CNY 230/t CO_2 as costs for CCUS technology fall with greater deployment and CCUS requires less, though still significant, financial incentives from the ETS to compete with other technologies (Figure 3.5, see also Figure 4.8 on average generation cost by technology in Chapter 4).

The intensity-based design shapes how the allowance price impacts different technologies. Under this design, generators receive allowances in proportion to their production activities and predetermined benchmarks for free, i.e. the more electricity they generate, the more free allowances they will be able to receive. Therefore, the effective CO_2 cost (in CNY per kWh of generation produced) incurred to a unit depends on: i) the allowance price (in CNY/t CO_2), and ii) the difference between a unit's emissions intensity and its applicable benchmark (in g CO_2/kWh), instead of its absolute emissions intensity. A unit faces an effective cost under the ETS only if it generates electricity at an emissions intensity exceeding the applicable benchmark, while other units performing better than the benchmark (i.e. at a lower emissions intensity) receive more free allowances than they need to surrender and can gain financially by selling the surplus.

Figure 3.5 Average effective CO_2 cost by technology and allowance price in the RPS-ETS Scenario, 2020-2035



Notes: CFB = circulating fluidised bed. Negative values in CO_2 cost imply that units of that technology on average receive an allowance surplus and could make a financial gain. The average CO_2 cost for coal power with CCUS in 2020 and 2025 indicate the potential gain CCUS could have made under the assumed emissions intensity benchmark and allowance price. In the model. However, it is not sufficient to make CCUS cost-competitive and enter the generation mix by 2025.

Under the ETS benchmark trajectory analysed in the RPS-ETS Scenario, the effective CO_2 cost – the cost generators actually need to pay for purchasing allowances to meet ETS compliance – would be below CNY 0.005/kWh for most unabated coal-fired power technologies in 2020-2025. Ultra-supercritical coal units and CFB units might even receive a financial incentive as they on average perform better than their respective benchmarks. Consequently, in the RPS-ETS Scenario, the ETS leads to a slight shift within the unabated coal generation from high-pressure, subcritical and supercritical units to ultra-supercritical and CFB units.

As benchmarks gradually tighten by 2030, most unabated coal technologies – including ultra-supercritical units – would have a higher emissions intensity than their benchmarks and face an actual CO_2 cost. As a result, unabated coal generation is reduced as are ultra-supercritical capacity additions – to 90 GW, compared to 140 GW in the RPS Scenario. Through 2035, the effective CO_2 cost remains on average below CNY 0.050/kWh for all coal sub-technologies and for the dominant ultra-supercritical units below CNY 0.020/kWh (Figure 3.5).

At the same time, with the increasing allowance price, the ETS would provide CCUS-equipped coal units with a significant CO_2 abatement "subsidy" of CNY 0.200/kWh as long as they are subject to the same benchmark as conventional unabated coal units above 300 MW. By providing this financial incentive, the ETS could make CCUS-equipped coal power cost-competitive in certain regions and allow it to enter into the power mix by 2030.

Meanwhile, gas generation receives a much smaller financial gain of around CNY 0.010/kWh as the benchmark for gas units is much closer to their actual emissions intensity, producing only a limited allowance surplus. Renewables and nuclear generators face neither direct cost nor gain because they are not included in the benchmark design and do not receive allowances under the ETS.

If a coal power generator switches therefore from coal to gas or non-fossil generation sources, the generator will lose free allowances associated with the coal power production, and receive allowances under the gas benchmark or no free allowances in case of switching to nuclear or renewables. Hence, the ETS incentive for switching from coal to alternative fuels depends primarily on how the CO_2 cost imposed on unabated coal generation impacts the relative cost competitiveness to other generation sources. Due to the design of the intensity-based system, the ETS incentive to reduce the emissions intensity of coal power generation, including through CCUS, is greater as it consists of both the avoided CO_2 cost and a substantial financial gain from surplus allowances.

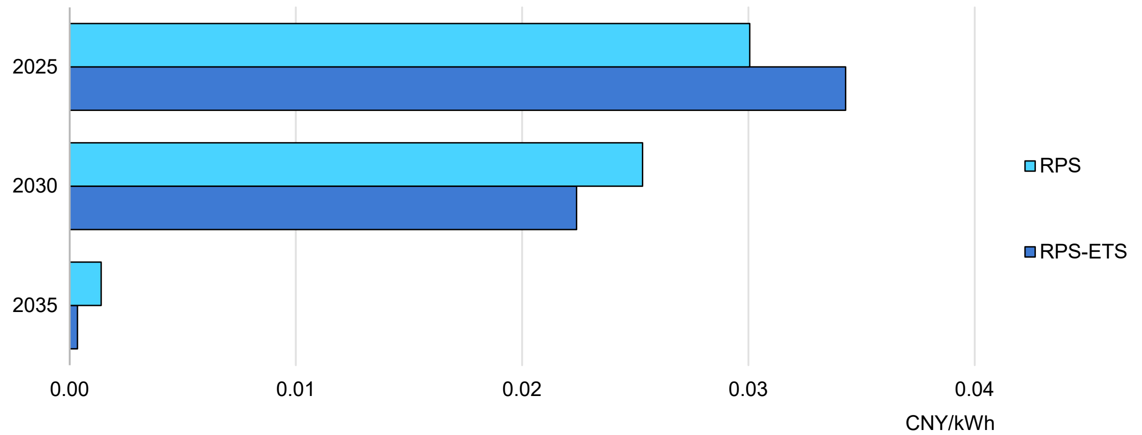
Overall, the intensity-based ETS design with free allocation and multiple benchmarks rewards better performers and penalises worse performers *relative to their respective benchmarks.* However, it also creates differentiated carbon pricing signals to technologies depending on the definition of benchmark categories and stringency. It provides the strongest incentive to measures that could reduce emissions *intensity* from covered generation sources to below-benchmark level, while providing limited incentives for fuel switching to lower-carbon sources that are subject to a different benchmark or those not included in the allowance allocation such as renewables – especially as compliance occurs at the company level.

Interaction of ETS and RPS

In addition to the power mix and CO_2 cost dynamics, the green electricity premium provides an indicator for understanding how the intensity-based ETS would interact with the RPS policy and the financial support required to ensure the targeted non-hydro renewables share (Figure 3.6). This involves not only renewables competing with fossil-based generation in new additions, but also competing with existing fossil-based capacity in the generation mix. Overall, the interaction observed is rather minimal.

In the RPS-ETS Scenario, the green electricity premium amounts to CNY 0.034/kWh in 2025, slightly higher than in the RPS Scenario. This is because with the assumed moderate benchmark tightening before 2025, the ETS incentivises higher running hours for more efficient coal- and gas-fired power plants, thereby increasing their relative cost competitiveness vis-à-vis less efficient coal and gas plants but also other generation sources such as renewables. In turn, to encourage the same deployment level of non-hydro renewables, a higher financial incentive is required. By 2030, the ETS imposes a positive CO_2 cost on all unabated coal technologies as benchmarks are tightened further, and consequently the green electricity premium falls to CNY 0.022/kWh – 12% below the level of the RPS Scenario. This trend continues to 2035 with the premium level dropping almost to zero.

Figure 3.6 Green electricity premium in the RPS and RPS-ETS Scenarios, 2025-2035

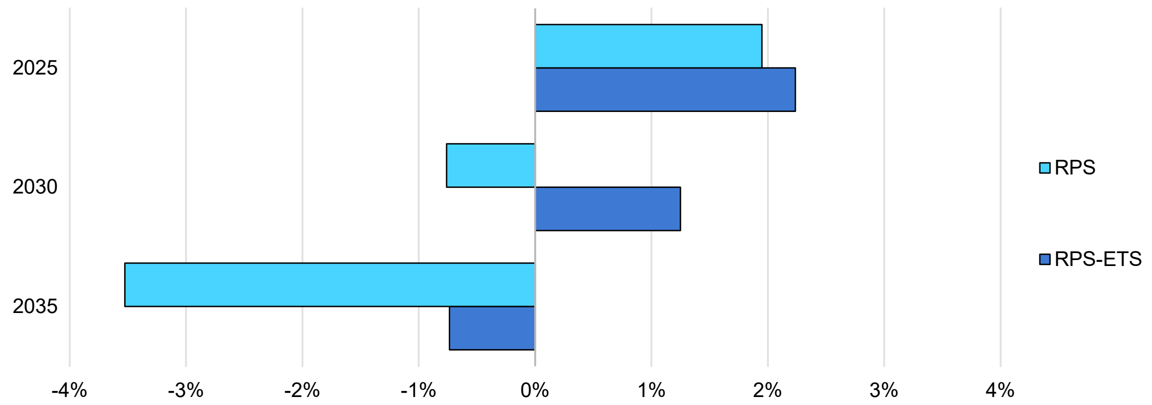


The result shows that when the ETS acts to improve efficiency and emissions intensity of fossil-based generation, it could have implications for the relative cost competitiveness with other generation sources. If the ETS is modest in stringency, it gives some incentive for slightly lower-carbon fossil-based generation, which results in the need for more support given to renewables to achieve the targeted deployment levels. When the ETS is more stringent, however, the CO_2 cost on fossil-based generation, even if modest, improves the cost competitiveness of renewables deployment and lowers the required "green premium". Nonetheless, the observed interaction effects in the RPS-ETS Scenario remain limited to 2035.

Electricity generation cost

The integration of a higher share of renewables in the electricity system and the internalisation of CO_2 costs affect the development of electricity generation cost to a limited extent (Figure 3.7). In the RPS Scenario, unit electricity generation cost increases in the period to 2025 by 2% as a higher share of renewables is integrated into the system which requires additional capital investment as well as balancing and storage costs. However, as deployment drives cost reductions, electricity generation costs also decrease after 2025.

Figure 3.7 Change in unit electricity generation cost relative to 2020 in the RPS and RPS-ETS Scenarios, 2025-2035



The RPS-ETS Scenario follows a similar trend, albeit at a slightly higher level. The internalisation of CO_2 costs has a moderate impact on electricity cost that becomes more identifiable by 2030. As benchmarks tighten and the allowance price increases to around CNY 230-285 per tonne of CO_2 post 2030, the unit electricity cost in the RPS-ETS Scenario is about 1.5% to 3% higher than in the RPS Scenario in the period 2030-2035. This is, however, against the backdrop of an additional 13% reductions in emissions that the ETS can generate compared to the RPS only scenario.

Chapter 4. Enhanced ETS designs for carbon neutrality

In 2020, China announced that it aims to peak CO_2 emissions before 2030 and become carbon neutral before 2060. The rapid decarbonisation of power supply alongside the electrification of a wide range of energy end-uses across all sectors are an important pillar of any strategy for achieving carbon neutrality. In order to support economy-wide carbon neutrality before 2060, China's power sector would likely need to achieve net zero CO_2 emissions before 2055 (IEA, 2021a). This chapter analyses three possible policy scenarios with strengthened ETS designs that could accelerate the alignment of the electricity sector's emissions trajectory with China's carbon neutrality target, using the emissions trajectory of the IEA's Announced Pledges Scenario (APS)[25] as input. Assuming the same RPS policy assumptions as the RPS-ETS Scenario, these scenarios introduce different ETS design enhancements after 2025 with significantly tighter benchmarks (ETS+BM), partial allowance auctioning (ETS+Auction) or transitioning the intensity-based ETS to a cap-and-trade system (ETS+Cap). The key assumptions and differences among the Enhanced ETS (ETS+) Scenarios are explained in detail in Chapter 2 and presented in Table 2.2. The following sections discuss and compare the implications of these three policy designs for the emissions trajectory, the generation mix, their cost-effectiveness[26] and the interactions of the ETS with the RPS policy.

Impact on CO_2 emissions

As all three ETS+ policy scenarios aim to align with a pathway for reaching China's carbon neutrality target, they follow the same emissions trajectory with lower emissions relative to the RPS-ETS Scenario. In the RPS-ETS Scenario, CO_2 emissions from electricity generation decrease from about 4.5 Gt in 2020 by 5% until 2030 and by around 20% until 2035. While the RPS-ETS Scenario would successfully peak electricity-related emissions before 2030 and set emissions to

[25] The Announced Pledges Scenario (APS) is presented in the IEA's reports "An energy sector roadmap to carbon neutrality in China" and "World Energy Outlook 2021". There is no single pathway for energy sector emissions consistent with China's stated goals of achieving a peak in CO_2 emissions before 2030 and carbon neutrality before 2060. The APS presents one plausible pathway to carbon neutrality in China's energy sector in line with the country's stated goals. The IEA's report "An energy sector roadmap to carbon neutrality in China" also explores an Accelerated Transition Scenario (ATS) to assess the opportunities for and implications of a faster transition through enhanced climate policy ambitions and efforts to 2030.

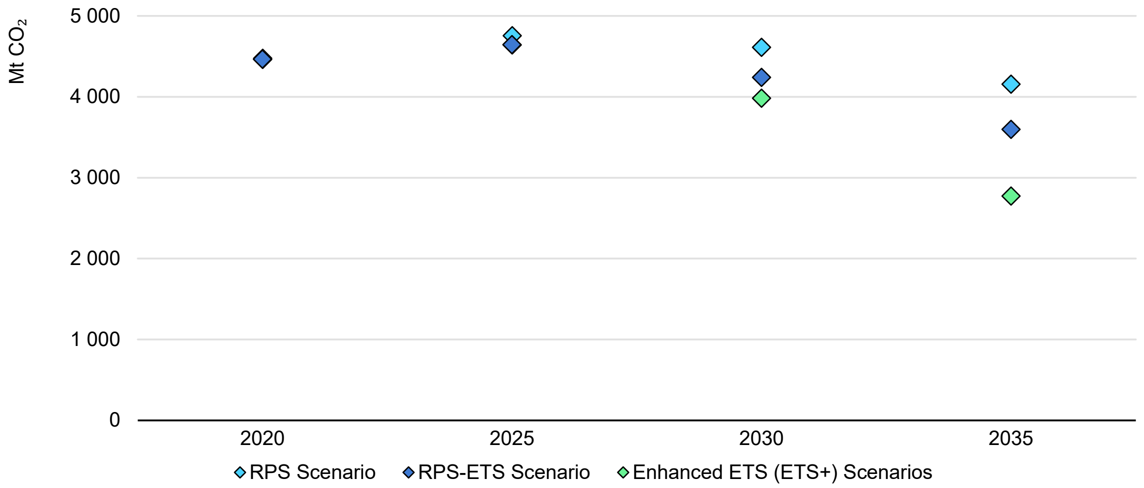
[26] Cost effectiveness is defined as the policy mix that can achieve a given emissions trajectory at lower financial cost. This report estimates the cost in terms of total system cost and in terms of unit electricity generation cost (i.e. the cost of generation per kWh produced).

further decline by 2035, much stronger policy tightening and faster emissions reductions would be necessary after 2035 to align the sector with carbon neutrality.

Combined with the same RPS targets, the three ETS+ Scenarios offer different means of using the ETS to achieve one electricity sector emissions trajectory that could better align with the carbon neutrality target. Through different ETS design enhancements after 2025, emissions reductions in the sector could be doubled by 2030 and electricity-related CO_2 emissions could decrease by 38% in 2035 compared to 2020, falling to 2.8 Gt CO_2 (Figure 4.1):

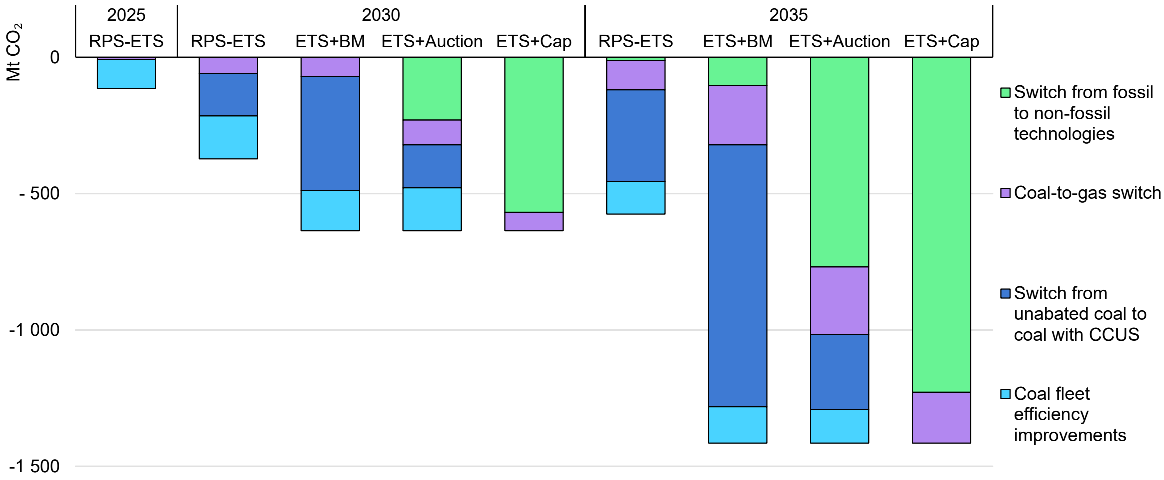
- **ETS+BM Scenario:** Significantly tightening the coal benchmarks post 2025, doubling the five-year tightening rate to 12% in the period to 2030 and increasing it again to 22% in 2030-3035. Overall, coal benchmarks are reduced to 67% of their 2020 level by 2035, compared to 86% in the RPS-ETS Scenario.
- **ETS+Auction Scenario:** Gradually introducing partial auctioning in the intensity-based ETS post 2025, with 17.5% of the allowances auctioned by 2030 and 23.5% by 2035, while tightening the coal benchmarks at the same pace as in the RPS-ETS Scenario.
- **ETS+Cap Scenario:** Transitioning to a technology-neutral cap-and-trade ETS post 2025, with an absolute emissions cap at 89% of 2020 emissions level for 2030 and 62% of 2020 level for 2035.

Figure 4.1 CO_2 emissions trajectory from electricity generation by scenario, 2020-2035



Depending on its design, the ETS could drive emissions reductions through different channels (Figure 4.2). Comparing emissions reductions with the counterfactual RPS Scenario, an intensity-based ETS with free allocation (RPS-ETS and ETS+BM Scenarios) delivers most of the emissions reductions by transforming the coal fleet through improving unabated coal fleet efficiency and encouraging CCUS adoption in coal power from 2030 onwards. Moreover, the ETS+BM Scenario triples CCUS-related reductions to 950 Mt CO_2 in 2035 compared to around 330 Mt CO_2 in the RPS-ETS Scenario. With tighter benchmarks, fuel switching from coal to gas and non-fossil technologies also increases to some extent. However, this only makes up around 20% of decarbonisation, mostly fuel switching from coal to gas.

Figure 4.2 Emissions reductions by channel in the RPS-ETS and ETS+ Scenarios compared with the counterfactual RPS Scenario, 2025-2035



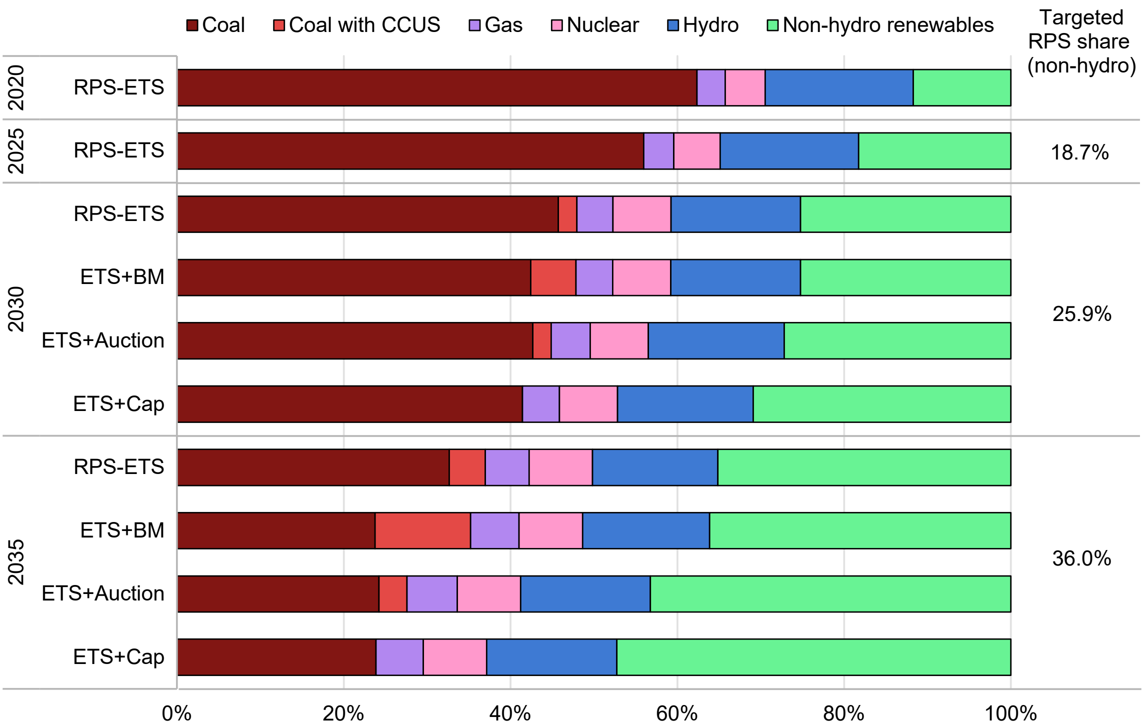
An intensity-based ETS with partial auctioning (ETS+Auction Scenario) generates emissions reductions through a combination of coal fleet transformation as well as fuel switching to gas and to non-fossil technologies, with the share of fuel switching-related reductions growing over time. By 2035, fuel switching to non-fossil technologies accounts for about 54% or almost 800 Mt CO_2 of emissions reductions in this scenario. Its emissions reduction from fuel switching to gas and unabated coal fleet efficiency improvements is similar in magnitude as in the ETS+BM Scenarios. Emissions reductions from coal power equipped with CCUS is much lower at around 280 Mt CO_2.

Transitioning from an intensity-based ETS to a cap-and-trade design significantly changes how the ETS drives decarbonisation. In the ETS+Cap Scenario, emissions reductions result entirely from fuel switching away from coal power – around 90% to non-fossil sources (reducing over 1 200 Mt CO_2 by 2035) and 10% to gas power (around 200 Mt CO_2). No emissions reductions are generated through efficiency improvements in the coal fleet compared to the counterfactual RPS Scenario nor through CCUS deployment. This is because operational efficiency does not improve due to all coal units seeing a reduction in running hours despite technical efficiency improvements of the coal fleet.

Impact on generation mix

Achieving China's carbon neutrality goal requires a strong and rapid shift to low-carbon power in the generation mix. The analysed ETS enhancements achieve the emissions trajectory by incentivising different low-carbon solutions, resulting in different generation mixes that impact coal and renewables in particular, while gas and nuclear remain similar across scenarios (Figure 4.3).

Figure 4.3 Electricity generation mix by technology and scenario, 2020-2035



All three ETS+ Scenarios accelerate the phase-down of unabated coal power generation as the ETS design is enhanced after 2025. Unlike in the RPS-ETS Scenario, where 40 GW of new unabated coal capacity is still built in 2025-2030, almost no new unabated coal capacity is added post 2025 in the ETS+ Scenarios, reducing the risk of emissions lock-in and stranded assets. By 2030, the share of unabated coal in total generation declines from more than 60% in 2020 to just over 40% – around 4% lower than in the RPS-ETS Scenario – with only slight differences across the ETS+ Scenarios. In all ETS+ Scenarios, unabated coal power plants generate around 2 800 TWh of electricity by 2035 compared with 4 800 TWh in 2020, and unabated coal's share of the generation mix declines to 24%. This is compared with 33% in the RPS-ETS Scenario by 2035. Except for ultra-supercritical coal plants, unabated coal power plants would on average have annual running hours below 2 500 hours, and serve mostly as a source for system security and flexibility.[27]

In the ETS+BM Scenario, the tightening of emissions intensity benchmarks leads to emissions reductions mainly through technology switch from unabated coal generation to coal power equipped with CCUS. Coal power generation with CCUS increases by more than 2.5 times to 1 340 TWh by 2035, providing 11% of total generation. Meanwhile, the shares of gas and non-fossil technologies remain at a similar level as the RPS-ETS Scenario, each increasing by only 1%.

Introducing partial auctioning of allowances in the ETS+Auction Scenario would allow the ETS to provide significant support to renewables by increasing the effective cost of carbon without having to tighten benchmarks as much as in the ETS+BM Scenario. The share of renewables generation increases to nearly 60% by 2035, 9% more than in the RPS-ETS Scenario. The share of non-hydro renewables reaches 43%, which surpasses the targeted RPS share by 7%. Coal power equipped with CCUS is deployed and contributes around 3% of total generation in 2035, slightly below the level in the RPS-ETS Scenario.

The ETS+Cap Scenario shows a more profound fuel switching trend in the generation mix. Transitioning the ETS from an intensity-based design to a cap-and-trade leads to a significant scale-up of non-hydro renewables: its share in the power mix reaches 47% by 2035, 11% higher than the RPS target and the level reached in the RPS-ETS Scenario. The share of all renewables increases to 63%, with hydropower generation increasing marginally. Fossil-based generation, on the other hand, falls below 30% – with 24% still coming from coal generation and 6% from gas generation. In contrast to the scenarios with an intensity-based ETS, ETS+Cap leads to no sizeable deployment of CCUS in the power sector by 2035 as coal power with CCUS cannot compete with renewables on a cost basis (see “Impacts of CO_2 costs on technologies” section below).

These results suggest that, as the ETS is strengthened through partial auctioning and especially as a cap-and-trade system, it can significantly accelerate the deployment of mature renewables as their costs have and are continuing to decrease. Both, ETS+Auction and ETS+Cap, surpass the targeted RPS share after 2030, indicating that additional financial support through RPS would no longer be needed for non-hydro renewables to reach their target.

Policy cost-effectiveness

While all ETS+ Scenarios achieve the same emissions trajectory for the electricity sector, they result in different costs for the electricity system. Transitioning to a

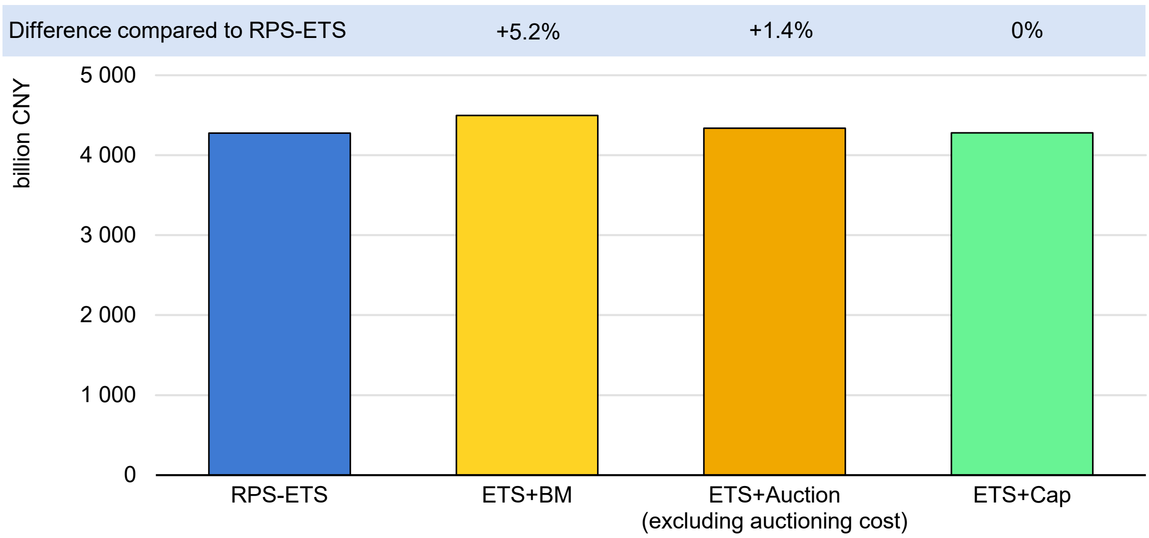
[27] To maintain the financial viability of plants with annual running hours below 2 500 and enable such plants to act as a source for system flexibility, support for flexibility retrofits and capacity markets would likely become necessary.

cap-and-trade system and gradually introducing partial auctioning into an intensity-based ETS demonstrate much stronger economic efficiency than a more stringent intensity-based ETS with complete free allocation.

Total system cost

By 2035, the ETS+Cap Scenario leads to the lowest total system costs[28] among the three ETS+ Scenarios (Figure 4.4). Compared to the RPS-ETS Scenario, which includes an intensity-based ETS with a moderate benchmark trajectory, the ETS+Cap Scenario achieves around 20% additional emissions reductions (over 800 Mt CO_2) at the same total system cost. It is followed by the ETS+Auction Scenario with 1% higher costs (when excluding costs for allowance purchase as they can be balanced at the system level with the resulting auctioning revenue), and the ETS+BM Scenario, which is 5% more costly. In 2035, achieving the same carbon neutrality-aligned trajectory would cost CNY 220 billion more with an intensity-based ETS with significantly tightened benchmarks (ETS+BM Scenario), than with a cap-and-trade system (ETS+Cap Scenario).

Figure 4.4 Total system costs by scenario, 2035



Unit electricity generation cost

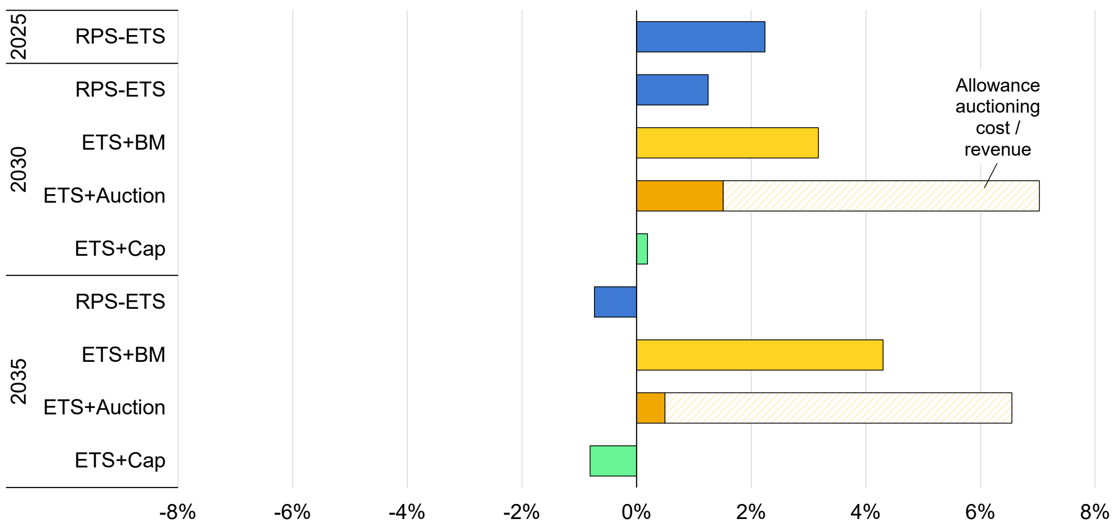
The cost-effectiveness of the different ETS enhancements is also reflected by the unit electricity generation cost[29] over time. In the RPS-ETS Scenario, unit

[28] In this report, total system cost includes annualised capital expenditure as well as variable and fixed operating and maintenance costs of electricity generation, transmission and balancing costs and costs for plant retrofits.
[29] The unit electricity generation cost is calculated as the total power system cost divided by total electricity generation.

electricity generation cost is at CNY 0.367/kWh in 2020, increases until 2025 and then decreases to 1% below 2020 levels by 2035.

Among the three ETS+ Scenarios, the ETS+Cap Scenario demonstrates the lowest unit cost for electricity generation in 2030 and 2035. As in the RPS-ETS Scenario, its cost level falls to 1% below 2020 levels by 2035 while delivering decarbonisation in line with China's peaking and neutrality targets (Figure 4.5). The cap-and-trade system achieves this cost-effectiveness by primarily driving fuel switching from unabated coal generation to whichever generation technology can deliver emissions reductions at the least cost. This leads to a switch to renewables as they offer more cost-efficient generation than coal power equipped with CCUS, which can be encouraged by an intensity-based ETS.

Figure 4.5 Change in unit electricity generation cost relative to 2020 by scenario, 2025-2035



In the ETS+Auction Scenario, unit electricity cost also falls post 2025 but still stands at 0.5% above the 2020 level by 2035. With 23.5% of allowances auctioned in 2035, the new carbon cost component introduced with partial auctioning reaches CNY 0.020/kWh which increases the unit electricity cost for generators by 6% above 2020 levels.[30] However, this carbon cost also represents a source of government revenue, which could reach more than CNY 260 billion in 2035. This revenue could be used to address affordability or competitiveness concerns

[30] While from a system perspective auctioning costs and revenues can be balanced, an electricity generator that has to purchase allowances still faces higher per unit electricity generation costs than before. A regulator can compensate a generator for that higher cost – this would, however, negate the desired effect of auctioning. This report, instead, takes a system perspective where a regulator reinvests the revenues to the benefit of electricity consumers.

by electricity end-consumers – especially if power producers are able to largely pass through the cost – and to lower the long-term costs of achieving carbon neutrality by investing the proceeds in less mature low-carbon technologies (Box 4.1) or energy efficiency measures.

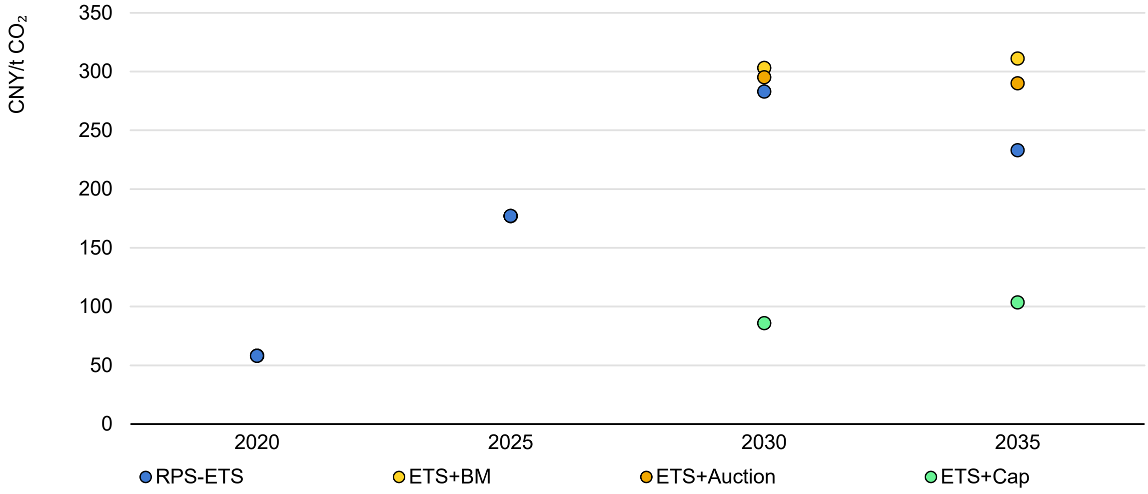
Enhancing an intensity-based ETS with free allocation through more stringent benchmarks alone leads to the least cost-efficient generation mix among the three. In the ETS+BM Scenario, unit electricity generation cost continues to increase post 2025, growing to 4% higher than 2020 levels by 2035 and 5% higher than in the ETS+Cap Scenario.

Allowance price

As the different ETS designs spur emissions reductions through different technology and fuel choices, allowance price levels also vary across scenarios (Figure 4.6). The same emissions reductions can be achieved with a much lower allowance price when transitioning to a cap-and-trade system (ETS+Cap), which encourages cost-efficient fuel switching to renewables with an allowance price of around CNY 100/t CO_2 in 2030-2035. An intensity-based ETS, whether with free allocation (ETS+BM) or partial auctioning (ETS+Auction), would instead lead to a higher allowance price of around CNY 300/t CO_2 as it mainly – or partially in the case of ETS+Auction – drives the required emissions reductions through CCUS deployment which needs higher financial support and, hence, determines the allowance price level. These stark differences between ETS+Cap and an intensity-based ETS design (RPS-ETS, ETS+BM and ETS+Auction) are explained by the fact that the latter mainly – if not exclusively – allows only the active participation of fossil-based generation in the ETS through its coal and gas power benchmarks. Cheaper abatement options such as renewables are excluded by the system's design whereas in a cap-and-trade system all generation sources can actively participate in meeting the emissions cap.

The results also suggest that careful management of market expectations may be needed if a transition to a cap-and-trade system is to take place, so that potential allowance price changes would not be misinterpreted as reduced policy commitment or stringency and potential price volatility is moderated.

Figure 4.6 Allowance price by scenario, 2020-2035



Box 4.1 ETS and technological innovation

The cost-effectiveness of a climate policy over time is also influenced by the degree to which it can incentivise technological innovation to bring down the future costs of decarbonisation. In the short-term, an ETS delivers cost-effective emissions reductions if its design can ensure that operational and investment decisions by generators lead to the cheapest abatement: for example, if a company decides to run its less efficient coal plants less and its more efficient ones more, as well as deploy mature low-carbon technologies such as solar PV due to the rise in CO_2 price or tighter benchmarks. Over the long-term an ETS can ensure cost-effectiveness if the system can generate a consistent and sufficient signal of rising CO_2 prices in the future, to lead a company to deploy more nascent technologies such as CCUS with the expectation of future gains due to this investment or to increase R&D expenditure for less mature renewables or CCUS for cheaper deployment in the future. Thus, the design of an ETS decides on whether it can deliver emissions abatement cost-effectively for the near- and long-term. In any case, however, as an ETS can only provide a financial signal that would often not be sufficient for nascent technologies, additional companion policies targeting technological innovation and necessary infrastructure – which are essential elements of any comprehensive energy policy – will always be required to complement an ETS (IEA, 2011).

In China's case, an intensity-based ETS with free allocation can support technological innovation only if a corresponding benchmark exists. The results of the modelling indicate that China's current design especially supports gradual efficiency improvements within the unabated coal fleet, while by 2030 also incentivising relatively more expensive, less mature CCUS. An intensity-based ETS with partial auctioning could combine both incentives for near-term and longer term cost-effectiveness to some extent by enabling renewables deployment and CCUS. A cap-and-trade design, on the other hand, would provide the strongest incentive for deploying cost-competitive renewables, while special provisions such as additional free allowances for nascent technologies would likely be needed to strengthen its signal for technology innovation.

In all cases, however, additional policies that complement the ETS will be necessary to ensure a diversified package of decarbonisation solutions for the long-term. For example, the modelling in this report assumes a 45% cost reduction in CCUS capital costs by 2035 as a result of exogenous support factors such as government and corporate R&D support as well as international learning effects. The EU's Innovation Fund is a good example of complementary innovation support for an ETS: the fund is financed through some of the proceeds generated from allowance auctioning in the EU ETS and aims to support early-stage, breakthrough low-carbon technologies (European Commission, 2022).

Crucially, the strongest incentive for innovation that China's ETS can provide is to create regulatory transparency and clarity for benchmark tightening or cap reduction – depending on the ETS design – over a long time horizon that enables market participants to robustly forecast rising stringency and, as a result, rising carbon prices. A carbon floor price that establishes a minimum carbon price, as in the UK, can be an additional design feature to create greater predictability and to contribute to de-risking investments in more nascent technologies.

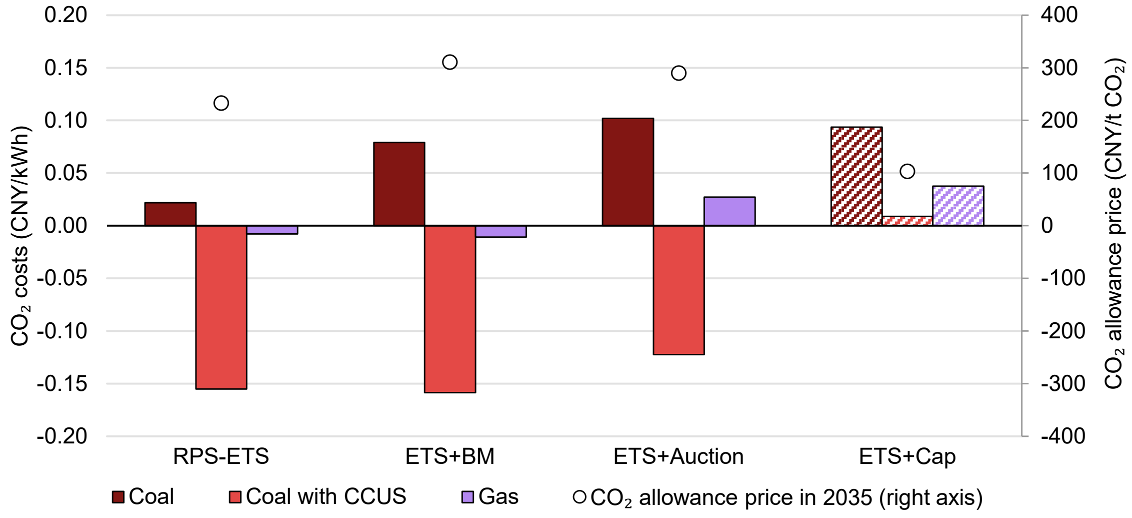
Impacts of CO_2 costs on technologies

The CO_2 cost signal for different generation technologies varies depending on the ETS design. In an intensity-based ETS with 100% free allocation (RPS-ETS Scenario and ETS+BM Scenario), the impact of the ETS on fossil-based generators depends on the allowance price level and a generator's relative performance compared to the applicable benchmarks. Those underperforming the benchmark incur an effective CO_2 cost, those outperforming it in terms of emissions intensity can make a financial gain. In these scenarios, how benchmark categories are defined, and their stringency are the key driver for ETS impact. With the introduction of partial auctioning (ETS+Auction Scenario), the ETS's incentive for decarbonisation is enhanced as it effectively reduces the number of free allowances and increases the effective CO_2 cost without having to lower the emissions intensity benchmark as much. However, it also reduces part of the CO_2 "subsidy" received by benchmark outperformers.

Transitioning to a cap-and-trade design would shift the ETS's focus from encouraging emissions intensity improvements in benchmark-covered fossil-based generation to reducing absolute emissions. In addition, it allows different emissions reductions measures to contribute to meeting the emissions cap. The CO_2 cost signal provided by a cap-and-trade system depends on the allowance price, a generators' absolute emissions and the relative cost competitiveness of generation technologies, rather than how their emissions intensity compares against their respective intensity benchmark. As a result, a sufficiently high CO_2 cost signal can be transmitted with a much lower allowance price in the ETS+Cap Scenario than in the two ETS+ Scenarios with intensity-based ETS designs (Figure 4.7). However, as the cap-and-trade design encourages the most cost-effective decarbonisation options across the entire generation mix, it does not incentivise CCUS adoption as coal power with CCUS cannot compete with renewables on a cost basis to 2035.

In all three Enhanced ETS Scenarios (ETS+), strengthened ETS designs lead to a significantly higher CO_2 cost signal for unabated coal power by 2035. In those scenarios, the CO_2 costs for unabated coal generation reach CNY 0.080-0.100/kWh compared to CNY 0.020/kWh in RPS-ETS (Figure 4.7). When it comes to coal with CCUS and gas power, the ETS' CO_2 cost signal varies considerably depending on scenario and ETS design. An intensity-based ETS with free allocation (ETS+BM) provides the strongest incentive to CCUS-equipped coal power with a CO_2 "subsidy" (i.e. a negative CO_2 cost) of CNY 0.160/kWh – illustrating the powerful effect of only allowing the active participation of fossil generation through technology-specific coal and gas power benchmarks in complying with the ETS and, hence, coal power with CCUS outperforming the coal benchmark. This effect is reduced under partial auctioning (ETS+Auction) due to a decrease in the quantity of free allowances received through the benchmarks and removed under a cap-and-trade (ETS+Cap) that allows all generation sources to participate in the ETS. Gas power on average receives a small "subsidy" of CNY 0.010/kWh in the ETS+BM Scenario but faces a positive CO_2 cost signal under auctioning and a cap-and-trade design. Introduction of auctioning or transitioning to a cap would thus significantly reduce the relative attractiveness of CCUS adoption in favour of renewables.

Figure 4.7 Allowance price and average CO_2 cost signal by technology by scenario, 2035



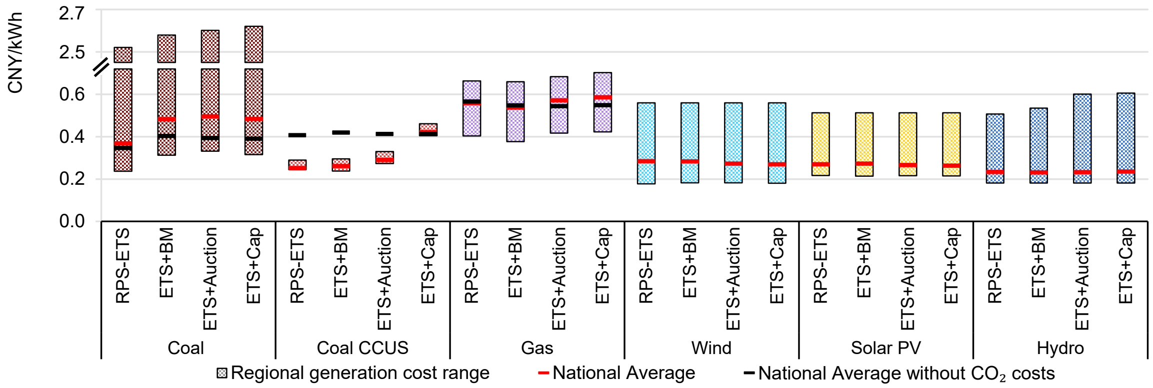
Note: In contrast to scenarios with an intensity-based ETS, the CO_2 costs by technology in the ETS+Cap Scenario need to be interpreted as opportunity costs rather than effective CO_2 costs that generators pay for allowance purchases in the other scenarios. The ETS+Cap costs shown would be the average CO_2 opportunity cost to a generator for producing a kWh of electricity with the respective technology if not switching to a non-fossil technology.

The resulting CO_2 costs from the different ETS design enhancements cause substantial changes in generation costs across technologies and scenarios (Figure 4.8) which explains the decarbonisation and generation mix patterns in the different scenarios. Across all ETS+ Scenarios, by 2035, the CO_2 cost increases the average generation cost of unabated coal power significantly by about 25% to almost CNY 0.5/kWh.[31] Correspondingly, it also pushes upwards the range of generation costs for unabated coal power across China's different provinces. In addition, as the ETS+ designs lead to less unabated coal power production and lower running hours, these scenarios also impact other cost components for coal power generation on a per kWh basis, in turn further decreasing its cost competitiveness vis-à-vis other, less carbon-intensive technologies. As coal power equipped with CCUS receives a sizeable CO_2 "subsidy" in the intensity-based ETS designs (RPS-ETS, ETS+BM and ETS+Auction Scenarios), its average generation cost drops notably from more than CNY 0.40/kWh to around CNY 0.25-0.30/kWh in regions where coal fuel costs are relatively low.[32] This enables coal with CCUS in such regions to be competitive with renewables in these scenarios. In the ETS+Cap Scenario, however, the transition from intensity-based benchmarks for fossil power generation to a stringent, absolute

[31] In the ETS+Cap Scenario, the CO_2 costs represent an opportunity cost for continuing fossil-based generation in contrast to an effective CO_2 cost as applied in the other scenarios.
[32] Plant running hours are a result of the model optimising total system costs under economic dispatch and policy constraints (such as the adoption of an RPS and ETS). A maximum 85% capacity factor is set for coal plants. As a result, the model produces higher average running hours for CCUS-equipped coal plants than for unabated coal plants.

emissions cap with no technology-specific benchmarks removes the CO_2 "subsidy" that CCUS could receive by outperforming the benchmarks in an intensity-based system. This leaves mature renewables as the most cost-competitive generation sources in the ETS+Cap Scenario, which leads to a generation mix dominated by mature renewables. The following sections discuss in more detail how each ETS design impacts the CO_2 cost for technologies.

Figure 4.8 Generation costs by technology and scenario, 2035



Notes: Generation costs in all scenarios are impacted by running hours and geographical distribution under economic dispatch. Coal power equipped with CCUS is only deployed in regions with low coal fuel costs (Inner Mongolia, Xinjiang, Shanxi and Ningxia). As no coal power equipped with CCUS is deployed in the ETS+Cap Scenario, the range and average cost values represent hypothetical generation costs. In contrast to scenarios with an intensity-based ETS, CO_2 costs in the ETS+Cap Scenario need to be interpreted as opportunity costs rather than effective CO_2 costs that generators pay for allowance purchases. This average CO_2 opportunity cost is the cost to a generator for producing one kWh of electricity with the respective fossil fuel instead of switching to a non-fossil technology.

Increased benchmark stringency in an intensity-based ETS

In an ETS that continues to adopt an intensity-based design with free allocation, as in the ETS+BM Scenario, tightening the emissions intensity benchmarks over time is key to driving more emission reductions. In order to deliver the additional emissions reductions needed to meet a carbon neutrality trajectory, the ETS+BM Scenario requires coal benchmarks to be about 20% lower by 2035 than in the RPS-ETS Scenario.

This increased benchmark stringency results in a substantial increase in CCUS-equipped coal generation as such plants can outperform the benchmarks. On the other hand, unabated coal generation produces a larger allowance deficit as even the most efficient ultra-supercritical coal plants reach technical limits for further emissions intensity reductions. As a result, unabated coal generators need to purchase an increasing amount of allowances from the market to enable compliance and the CO_2 cost makes them partly uncompetitive compared to CCUS-equipped coal power plants. This is because the greater benchmark stringency requires the development of fossil-based generation with low emissions intensity that can outperform coal benchmarks to balance allowance demand and supply. The support for non-fossil generation such as renewables or nuclear remains very limited because they cannot act as a source of allowance supply, and in case of fuel switching to non-fossil generation, the generator would lose the free allowances allocated to his reduced coal- or gas-fired power production, thus cannot directly gain allowance surplus from the switching. Efficient gas generation can only marginally outperform the gas benchmark.

In turn, such a system also produces a higher allowance price than if a wider range of technologies – including cheaper abatement options than CCUS – can contribute to meeting the allowance demand under the ETS. In the ETS+BM Scenario with highly stringent coal benchmarks, the allowance price rises to over CNY 300/t CO_2 in 2035. The effective CO_2 cost for unabated coal generation in the ETS+BM Scenario reaches on average CNY 0.080/kWh in 2035. At the same time, CCUS-equipped coal generation receives an abatement “subsidy” of CNY 0.160/kWh in 2035 as the technology benefits from selling surplus allowances. Gas generation benefits at a much lower level of CNY 0.010/kWh.

Overall, financial incentives for switching from unabated to CCUS-equipped coal generation amount to nearly CNY 0.250/kWh in 2035 in the ETS+BM Scenario – taking into account the avoided CO_2 cost for unabated coal and the available financial gain for CCUS-equipped coal generation. This is compared to less than CNY 0.090/kWh for gas generation (Figure 4.7).

Partial auctioning in an intensity-based ETS

Introducing partial auctioning into an intensity-based ETS – as done in the ETS+Auction Scenario – enhances the stringency of the system by increasing the share of allowances that generators need to purchase, thus increasing the effective CO_2 cost that fossil-based generators would face. Therefore, an intensity-based ETS with auctioning does not need to tighten the benchmarks as much as in a free allocation system (see ETS+BM Scenario). It does not require as much development of fossil-based generation with *low emissions intensity* to enable compliance and allow the system to balance allowance demand and supply.

Partial auctioning reduces the amount of freely allocated allowances to fossil-based power generators, for both those that outperform and underperform their respective benchmarks. For example, if 20% of allowances are auctioned, generators receive 80% of allowances for free. Generators that already have a higher emissions intensity than the benchmark would need to purchase 20% of the originally freely allocated allowances on top of the allowances they are required to purchase for underperforming the benchmark. Generators that outperform benchmarks by a moderate margin (e.g. 5%) would face an allowance deficit instead of an allowance surplus, as partial auctioning of 20% would require them to purchase around 15% of allowances that they could receive under fully free allocation. For generators that significantly outperform benchmarks, such as CCUS-equipped coal power, auctioning would reduce the level of surplus free allowances they receive, in turn decreasing their financial gain. In this way, partial auctioning can increase the effective CO_2 cost for unabated fossil-based generation and increase incentives to switch to low-carbon technologies. At the same time, it also reduces the "subsidy" provided to fossil-based emissions reductions solutions and enhances the relative attractiveness of other decarbonisation options such as non-fossil technologies.

With around a quarter of allowances auctioned in 2035, the average effective CO_2 cost for unabated coal power increases to CNY 0.100/kWh in the ETS+Auction Scenario. This compares to CNY 0.020/kWh in the RPS-ETS Scenario, which has the same benchmark stringency but allocates all allowances for free. For gas generation, the CO_2 cost increases to CNY 0.030/kWh in 2035 compared to a "subsidy" of CNY 0.010/kWh in the RPS-ETS Scenario. Auctioning also reduces the considerable financial benefit available to CCUS-equipped coal power from CNY 0.160/kWh in the RPS-ETS Scenario to CNY 0.120/kWh. This higher CO_2 cost for all unabated coal and gas generation, as well as a lower incentive for CCUS, also holds in comparison to the ETS+BM Scenario (Figure 4.7).

This change in effective CO_2 costs and subsidies allows the ETS to incentivise more fuel switching to non-fossil generation, while still providing some support to CCUS deployment. Consequently, the share of renewables in the ETS+Auction Scenario is 9% higher in 2035 than in the RPS-ETS Scenario, reaching 59% of generation. CCUS-equipped coal reaches 3% of the generation mix.

Cap-and-trade

The transition from an intensity-based system to a cap-and-trade system with an absolute emissions cap would significantly change how the ETS drives power sector decarbonisation. Such a design evolution would shift the system's focus from emissions intensity improvement to absolute emissions reductions, and allow different emissions reductions measures to contribute to meeting the emissions constraint (i.e. the cap). This would provide a more effective support to fuel switching to non-fossil generation. In the ETS+Cap Scenario, the share of renewables reaches 63% in 2035, the highest level across all Enhanced ETS Scenarios. It is the only scenario that shows no CCUS deployment by 2035.

The inclusion of an absolute emissions cap predetermines the total allowances supply and, provided that the cap is sufficiently stringent, requires decarbonisation measures to be taken until total emissions from covered entities are reduced to meet the absolute cap. In contrast to an intensity-based system, increasing fossil-based generation output cannot lead to more free allowances in the system.

Therefore, the cap-and-trade system values the reduction of one tonne of CO_2 equally – whether achieved by efficiency or emissions intensity improvement or by fuel switching. Through this, the system incentivises the most cost-effective decarbonisation opportunities.

With a cap-and-trade design, the ETS sends a uniform CO_2 price signal to all power generating technologies – not just a subset of fossil-fuelled ones, as is the case in an intensity-based system. The CO_2 price represents an opportunity cost for not switching to the next cheapest lower-carbon generation, taking into account the allowance price, relative technology cost and emissions cap level. With a stringent cap that decreases over time, fossil-based generators must continuously decrease emissions; those that do not receive enough free allowances would need to purchase additional allowances from other generators, or avoid this cost by reducing emissions. For generators that do receive sufficient free allowances for ETS compliance, there is an opportunity cost for emitting rather than potentially gaining by selling unused allowances. Under a cap-and-trade system, generators must weigh the opportunity cost for keeping an emitting generation asset and the cost for adopting a lower-carbon solution, and to reduce emissions where the latter is cheaper. At the same time, as generators will seek to pass through this opportunity cost to electricity customers in an economic dispatch system, partial auctioning can be useful in mitigating potential windfall profits.

As a result of giving emissions reductions from fuel switching to cost-competitive non-fossil technologies equal value, a sufficiently high CO_2 cost signal can be transmitted with a much lower allowance price: the CO_2 cost signal for unabated coal reaches on average CNY 0.070/kWh in 2035 in the ETS+Cap Scenario – a similar level as in ETS+BM. This is while the allowance price remains at around CNY 104/t CO_2, about 65% lower than in the ETS+BM Scenario (Figure 4.7).

ETS effects on low-carbon alternatives would also change significantly with a transition to a cap-and-trade design. Without the benchmark-induced ‘subsidy’ for lower-intensity fossil generation, a cap-and-trade ETS would provide the strongest incentive for switching from unabated coal to non-fossil technologies. The ETS with a cap-and-trade design thus enhances in particular the competitiveness of renewables relative to other generation sources. Meanwhile, by 2035, the incentive for switching from unabated to CCUS-equipped coal in the ETS+Cap Scenario is not sufficient to make CCUS cost-competitive with other low-carbon generation sources. As a result, it does not enter the power mix as unabated coal generation is phased down.

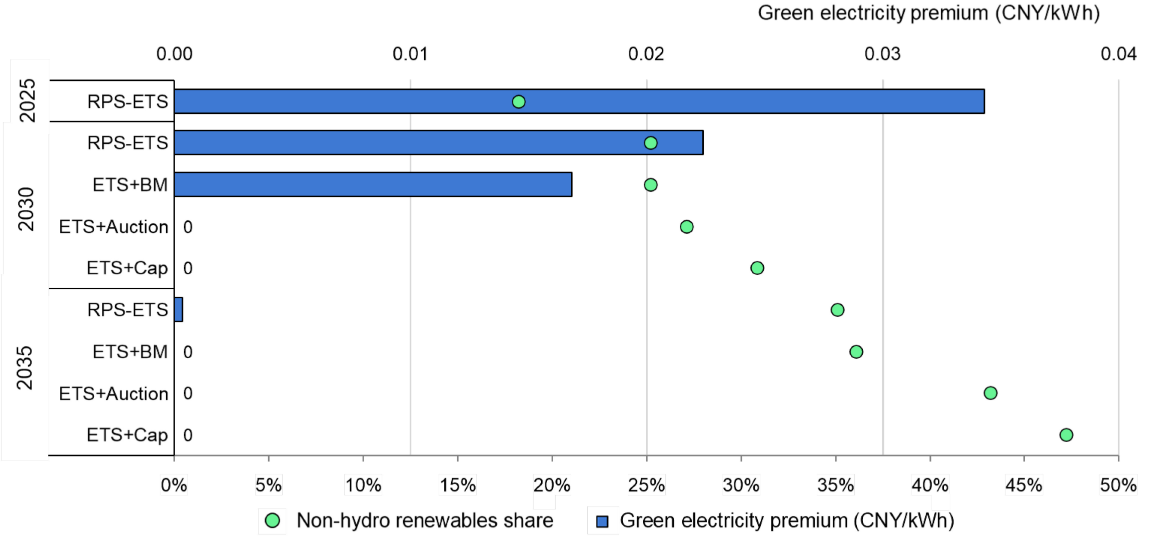
Policy interactions of ETS and RPS: impact on green electricity premium

The green electricity premium provides an indicator for understanding how the different ETS designs interact with the RPS policy, and in particular the financial support provided to non-hydro renewables. In all three ETS+ Scenarios, the green electricity premium needed to support the targeted non-hydro renewables share decreases as the ETS design is further enhanced post 2025. This indicates that the more stringent ETS designs provide an incentive that makes non-hydro renewables more cost-competitive relative to other generation sources. The level of support varies under different ETS designs, and the lower the green electricity premium generated by the model, the higher the ETS incentive towards non-hydro renewables.

In the ETS+BM Scenario, only limited support for renewables deployment is generated. In 2030, the green electricity premium falls to CNY 0.017/kWh which is 25% lower than in the RPS-ETS Scenario with less benchmark tightening. However, as the ETS+BM Scenario still produces a positive green electricity premium, the enhanced intensity-based ETS does not yet provide sufficient incentives to reach the targeted 25.9% share by 2030 and complementary financial support would be needed through, for example, the green certificate scheme. By 2035, however, the green electricity premium price in the ETS+BM Scenario falls to zero – in other words, the system could by then provide the required support to non-hydro renewables to reach a 36% share in power generation. Nevertheless, the premium level is already near zero in the RPS-ETS Scenario by 2035, showing that little additional support is needed; meanwhile, the ETS+BM Scenario increases the share of non-hydro renewables only marginally compared to the 36% target (Figure 4.9). These show that an intensity-based ETS with free allocation, even with highly stringent benchmarks, can only provide minor additional support to renewables' competitiveness and deployment, and complementary financial support would still be required to drive higher renewables uptake.

ETS support for non-hydro renewables is significantly stronger in the ETS+Auction Scenario and in the ETS+Cap Scenario. In both scenarios, the green electricity premium already falls to zero by 2030, indicating that no additional financial support through RPS would be required by then to reach the targeted share. This is also coherent with the generation mix outcome where the share of non-hydro renewables far exceeds the RPS target in both scenarios.

Figure 4.9 Green electricity premium and non-hydro renewables share by scenario, 2025-2035



Overall, the green electricity premium indicates that the ETS could evolve to be the primary instrument in driving a higher share of renewables in the electricity sector – however, only through the introduction of allowance auctioning or with a transition to a cap-and-trade system. By streamlining the ETS and RPS policies – for example, as in the ETS+Auction or ETS+Cap Scenarios – the cost-effectiveness of the policy mix could be improved and additional financial support for mature and cost-competitive renewables could be avoided or phased out over time. At the same time, these results suggest that potential ETS enhancements could impact existing renewables policy by putting downward pressure on the price level in the green certificate market. This, in turn, would require co-ordination and further policy intervention to manage market expectations and to guide investment decisions. Strengthening policy co-ordination in accordance with the channels and magnitude of policy interactions will help to seize policy synergies and enhance the effectiveness of the policy mix.

Box 4.2 Potential implications for CCER offsets inclusion

The inclusion of Chinese Certified Emissions Reduction (CCER) offset credits in China's ETS, in particular credits generated from renewables, forestry and methane utilisation projects (China, MEE, 2021a; China, State Council General Office, 2021), provides an opportunity for decarbonisation measures that do not directly fall within the benchmark coverage to generate allowances for the intensity-based system and make financial gains from the ETS.

However, the inclusion of offset credits in an ETS needs to be carefully managed so as not to undermine ETS stringency and price signals, as was the case in the second phase of the EU ETS. To avoid such adverse effects, China has set a limit for CCER use for compliance purposes of up to 5% of verified emissions. This means that while CCER inclusion offers a way for the ETS to provide direct incentives to some projects that do not target reducing emissions intensity of fossil-based generation, it would not fundamentally reshape the functioning of an intensity-based ETS. In particular, it does not change the fact that non-fossil generation cannot serve as a source of allowance supply in a systemic manner.

Furthermore, CCER supply is currently limited as rules governing CCER projects have been under revision since 2017, suspending issuance and approval of new credits. New CCER rules and further clarity on their inclusion in the national ETS are expected in 2022. Even assuming ample supply of CCER credits, however, unabated fossil-based generators would likely face allowance deficits higher than 5% of their verified emissions as benchmarks are tightened over time. Even if CCER inclusion offers a cheap opportunity for ETS compliance, demand would likely outpace supply significantly leading to a similar dynamic as demonstrated in the ETS+BM Scenario.

Therefore, CCERs provide an opportunity to somewhat diversify the sources of allowance supply in an intensity-based ETS. However, they are unlikely to provide a means of reducing overall CO_2 costs faced by generators, nor a systematic and large-scale channel to incentivise renewables – especially not to the extent of ETS design evolutions such as partial allowance auctioning or transitioning to a cap-and-trade design. Nevertheless, CCERs can provide some financial incentives to projects that currently receive limited policy support such as methane reduction and forestry.

Chapter 5. Policy insights

China's shift to a carbon neutrality target transforms the long-term policy priority away from improving emissions intensity to reducing absolute emissions. Consequently, the ETS design will likely need to evolve to reflect this change and there are several design options that can accelerate electricity sector alignment with a carbon neutrality trajectory. Nevertheless, each design option has different impacts on the electricity sector and there are different parameters that can be prioritised with different design choices. This chapter proposes policy insights by comparing the scenario results presented in the previous chapters with respect to their ability to achieve the different policy priorities: optimising total system cost, diversifying the generation mix, driving renewables deployment, improving and decarbonising the fossil fuel power fleet, and ETS revenue generation.

While considerations regarding energy security, distributional impacts and employment are also important parameters for policy design, they are outside of the scope of this report.

Different ETS design options should be considered in depth with respect to most relevant policy priorities

Total system cost after 2025 is lowest in the ETS+Cap Scenario where the intensity-based ETS is transformed into a cap-and-trade ETS. This is because a cap-and-trade ETS allows covered entities to identify and invest in the lowest-cost abatement option, thereby reducing the allowance price and driving lower-cost renewables generation. This is followed by the ETS+Auction Scenario which helps to drive significant renewables deployment through the added CO_2 cost from purchasing allowances. The ETS+Auction Scenario also has a lower allowance price than the ETS+BM Scenario, which has the highest total system cost. The significant benchmark tightening leads to a high allowance price and the deployment of a significant share of CCUS, which is comparatively more expensive than renewables deployment.

The most diverse generation mix, however, can be delivered by the ETS+Auction Scenario as it provides meaningful incentives for coal power with CCUS, renewables deployment, as well as some additional, efficient gas power generation. This is because the benchmark tightening of the intensity-based ETS provides a financial incentive for coal power with CCUS and efficient gas generation, while the added CO_2 cost through auctioning decreases the cost competitiveness of fossil-based power compared with renewables. The ETS+BM Scenario, on the other hand, leads to significant deployment of coal power with

CCUS while promoting renewables only marginally. The ETS+Cap Scenario results in a generation mix that is dominated by renewables with no CCUS-equipped coal power by 2035.

Consequently, if driving renewables deployment is a priority of China's ETS, the ETS+Cap Scenario performs best, followed by the ETS+Auction and then the ETS+BM Scenarios. This is because a cap-and-trade ETS allows renewables to directly participate in the emissions reduction required by the system and therefore, as a low-carbon power source, gain a significant competitive advantage over fossil-based generation. If introducing partial auctioning in an intensity-based ETS, this effect is reduced because renewables are not considered directly in the system through benchmarks but rather benefit from the added carbon cost applied to the most carbon-intensive power generation sources. In the ETS+BM Scenario with significantly tightened benchmarks, there is almost no incentive for additional renewables deployment from the ETS because the system requires the allowance deficit to be balanced with lower-carbon fossil fuel generation covered by benchmarks – in other words, by coal and gas power with CCUS.

On the other hand, if a priority of the ETS is to enhance the efficiency and reduce the emissions intensity of the existing fossil fuel power fleet, and to encourage development and deployment of currently immature CCUS technology for energy security, grid flexibility and employment considerations, then an intensity-based ETS, whether with free allocation but stringent benchmarks or partial auctioning, would have a stronger effect than a cap-and-trade ETS as the former directly targets the emissions intensity of coal and gas power. In the case of a cap-and-trade ETS, these policy goals could be supported through special provisions such as additional free allowances for CCUS-equipped units, or through companion policies dedicated to efficiency improvement and CCUS uptake. For the long-term carbon neutrality target, there will however be limits on technical efficiency improvements for existing infrastructure and storage capacity for CCUS and, thus, their potential to deliver emissions reductions. Furthermore, the deployment of CCUS technology would also require co-ordination with policy support to CCUS R&D and demonstration projects in the near- and medium-term, as well as support for CO_2 transport and storage infrastructure.

The generation of carbon revenues to address, for example, distributional concerns, energy efficiency or to support R&D in early-stage low-carbon technologies can be another priority. Such a priority, however, can only be addressed through the introduction of allowance auctioning as modelled in the ETS+Auction Scenario. The introduction of allowance auctioning is of course also possible in a cap-and-trade ETS, which has, however, not been part of the ETS+Cap Scenario presented in this report.

Thus, depending on the policy makers' priorities as well as the ability to navigate and negotiate complex policy co-ordination across several ministries, the impacts and consequences of the different ETS design options should be carefully considered. Such policy co-ordination can be aided by introducing a policy co-ordination process involving all relevant government institutions that aims to analyse ex-ante the impact of different policy mixes in order to avoid unintended consequences. Examples for this are the role of the Deputy Secretary General for Policy Co-ordination and the Regulatory Scrutiny Board at the European Commission. Finally, not all of the different ETS design options need to be mutually exclusive. The implementation of a combination of design options presented in the different ETS+ Scenarios is conceivable. An example is the transition to a cap-and-trade system with partial auctioning.

ETS as a key instrument to achieve carbon neutrality in China

Irrespective of the competing priorities, establishing the ETS as a means to deliver renewables targets cost-effectively – and, indeed, also to drive deployment of CCUS over time – could be a critical cornerstone to achieve carbon neutrality. Introducing partial auctioning in the coming years would allow China's ETS to provide such incentives with the intensity-based design, as well as to improve price discovery and generate an additional revenue source. By still involving meaningful benchmark reduction, it could incentivise the deployment of coal power with CCUS and significantly reduce the emissions intensity of the current coal power fleet. At the same time, the added CO_2 cost for fossil-based generation resulting from having to purchase auctioned allowances improves the cost competitiveness of renewables, especially compared to unabated coal power. The introduction of partial auctioning would also increase market liquidity and strengthen price discovery in China's ETS. The auction revenues could then be used to further accelerate technology innovation, to invest in energy efficiency and to address distributional concerns (e.g. for electricity end-consumers) – aspects that would lower the longer term cost of China's carbon neutrality path and improve the acceptability of the ETS.

The introduction of partial auctioning could be coupled with a fast implementation of announced plans on an extension to other sectors (e.g. industry) and a gradual transition to a cap-and-trade ETS towards the end of the decade. These would further reduce the overall cost of achieving carbon neutrality by expanding the possible options for emissions reductions and increasing the liquidity of the ETS. Opening market participation to non-compliance entities such as financial intermediaries could, in addition, serve to improve the liquidity and functioning of the market and – especially in an economic dispatch electricity market – allow power generators to hedge against carbon price volatility. The greater cost-effectiveness is achieved through the market-based design of the ETS which incentivises the lowest cost emissions reductions – irrespective of the sector or industry. Greater liquidity in the system is generated through an increased number of actors trading allowances, which should improve price discovery, moderate price swings and in turn aid the acceptance of the system. Furthermore, an extension of the ETS' coverage can also help to reduce the number and complexity of additional sectoral policies to achieve China's path to carbon neutrality.

Further design elements of such an ETS can also support the management of policy interactions: flexibility mechanisms to manage allowance volume or price volatility such as allowance reserves or price corridors. These can provide predictable and rapid adjustments if the ETS is not providing the intended price signal or causing negative impacts due to, for example, overlapping policies or external shocks. Similarly, communicating the future plans for China's ETS well in advance, including technical details such as benchmark or cap trajectories, will be crucial to provide visibility and planning certainty for market participants, guide plant management and investments decisions (including for technological innovation and necessary infrastructure for CCUS) as well as to accelerate generators' alignment with the carbon peaking and carbon neutrality goals.

Ultimately, to ensure full alignment of the ETS with the carbon neutrality target, a gradual shift to a cap-and-trade ETS towards the end of the decade would turn absolute emissions reductions into the overarching objective of the ETS. Such a system would introduce greater technology neutrality and achieve greater cost-effectiveness by increasing the incentive for fuel switching to lower-cost renewables over time – all the while ensuring the environmental effectiveness of the system through a cap aligned with the carbon neutrality goal. Partial auctioning could remain part of such a system, which would further strengthen the price signal, create revenue, and also mitigate potential windfall profits for companies where cost pass-through is possible. Free allowances, allocated using for example, product-based benchmarks[33] (instead of fuel or technology-specific ones), can be used to address competitiveness concerns – especially if extending the ETS to industry – or to mitigate the impact of rising CO_2 prices on electricity end-consumers.

[33] Product-based benchmarks for free allocation could mean, for example, one benchmark for electricity generation irrespective of the fuel or technology. In the case of industry, the product could be the main output such as crude steel for the iron and steel sector.

General annex

REPO model and modelling design

Introducing the REPO model

The Renewable Electricity Planning and Operation (REPO) model is a capacity expansion and dispatch model for China's power system. It is disaggregated at the provincial level and extends the open-source Balmorel model (Ravn, 2001) while incorporating important technology and policy characteristics particular to China (Yang et al., 2018).

The model integrates an endogenous capacity expansion module and applies an objective function to minimise the discounted total cost of the power system. The total power system cost comprises capacity investment costs, operations and maintenance costs, fuel expenses, unit commitment costs, transmission costs and taxes and subsidies. The REPO model covers China's 32 provincial-level administrative divisions (Table A.1).[34] These 32 divisions can be grouped into six major grid regions: Northeast Grid (NEG), Northwest Grid (NWG), North Grid (NG), Central Grid (CG), East Grid (EG) and South Grid (SG). Electricity and heat demand, resource potential, existing power and co-generation installations and existing transmission capacity are all represented at the provincial level. The model allows interprovincial trade up to the limit of transmission capacity.

The model takes 2015 as the base year and then iterates to 2035 in five-year increments. In each iteration, the model optimises capacity expansion and grid operations for one year. Within that year, the model selects 12 out of 52 weeks as representative seasons, and 6 hours of a typical day in each week as representative time slots. These 72 representative hours of a year are simulated for each area and each time period.

The model's provincial load curve projections to 2035 are generated based on electricity demand changes and the accurate load curves for 2015. The model covers coal-fired, gas-fired, nuclear, hydro, wind, solar and biomass power. It also includes pumped hydro, compressed air and chemical storage.

[34] The special administrative regions of Hong Kong (China) and Macau (China) are not included in this study. Inner Mongolia is disaggregated into Eastern and Western Inner Mongolia.

Figure A.1 REPO model framework

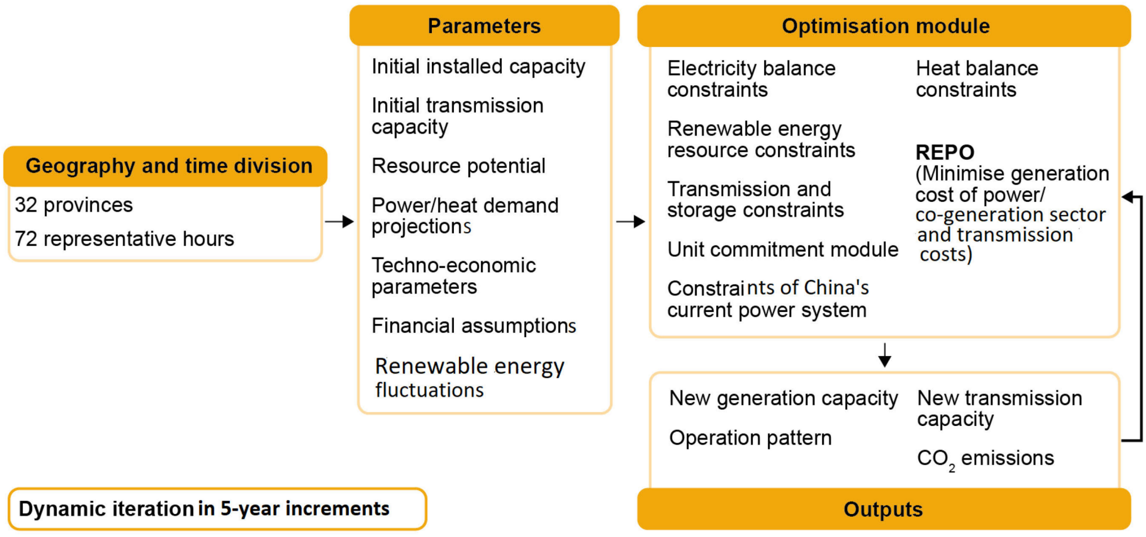


Table A.1 China power sector's 6 grid regions and REPO model's 32 provincial areas

Grid region	Provinces covered
Northeast Grid	Heilongjiang, Jilin, Liaoning, Eastern Inner Mongolia
Northwest Grid	Shaanxi, Gansu, Qinghai, Ningxia, Xinjiang, Tibet
North Grid	Hebei, Beijing, Tianjin, Shanxi, Shandong, Western Inner Mongolia
Central Grid	Hubei, Hunan, Jiangxi, Chongqing, Sichuan, Henan
East Grid	Shanghai, Jiangsu, Anhui, Fujian, Zhejiang
South Grid	Guangdong, Guangxi, Guizhou, Hainan, Yunnan

The REPO model's important constraints are: power balance constraints, power generation constraints, renewable energy resource constraints, transmission constraints, storage constraints, unit commitment constraint and planning reserve constraint. The power balance constraints ensure that power generation plus net imports equal power demand and losses, while power generation constraints ensure that the power generation of each technology at each hour does not exceed its capacity. As power generation from variable renewable energy (VRE) resources such as run-of-river hydro, wind (Rienecker et al., 2011) and solar (China Meteorological Administration, 2016) is also limited by resource availability, the renewable energy resource constraints ensure that each VRE technology's generation does not exceed its resource limit. The resource limit comprises two aspects: full-load hours and the maximum generation profile for each renewable generator in each region. For each VRE technology, generation is limited to the product of its full-load hours, installed capacity and share of total maximum generation for one time segment. With the model recognising all interprovincial transmission lines of more than 220 kV, its transmission constraints ensure that the amount of power transported from one region to another does not exceed the transmission capacity between the two regions. The storage constraints ensure that the charging and discharging rate of each storage technology does not exceed its power capacity and that energy storage does not exceed its energy capacity. The unit commitment constraint and planning reserve constraint ensure capacity margin for the typical load of each representative hour and for annual peak load.

The REPO model computes the future capacity expansion and power generation of each technology in each province, in addition to its CO_2 emissions. In line with most capacity expansion models, no construction times are considered. These data are used to analyse the effects of ETS policies on the power system.

To better represent thermal power technologies in the REPO model, we disaggregated coal-fired and gas-fired power into additional subcategories. Each technology is described by several parameters, including its efficiency, installation costs, fixed operations and maintenance (O&M) costs, variable O&M costs, lifespan, typical size, ramping up/down rate, startup/shut-down costs and minimum load share. Coal-fired power technologies are disaggregated into seven detailed categories: ultra-supercritical, supercritical 600 MW, supercritical 300 MW, subcritical 600 MW, subcritical 300 MW, high-pressure and ultra-high-pressure, and circulating fluidised bed (CFB). Gas-fired power technologies are divided into two categories: F-class and below F-class.

An ETS module is built into the REPO model to describe the national ETS. The technologies involved in the national ETS and their benchmarks are described in the model, with only coal- and gas-fired power technologies covered by the national ETS from 2020. Benchmark values are defined by technology and year. Some equations and constraints have been integrated into the ETS module to represent the allowance allocation rules.

Key data inputs and assumptions

This section details key data inputs and assumptions used in the modelling for this report, including on electricity demand, dispatch rules, initial capacity mix, costs assumptions and emissions factors.

Electricity demand for 2015 and 2020 are based on CEC data. Assumptions for future electricity demand are aligned with the IEA’s Announced Pledges Scenario (APS) (IEA, 2021b) (Table A.2).

Table A.2 Electricity demand assumptions

	2025	2030	2035
Electricity demand (TWh)	9 300	10 200	11 800

The model assumes partly planned dispatch in 2020 and economic dispatch from 2025 onwards, while allowing for interprovincial trade up to the limit of transmission capacity, and optimises capacity and generation mixes accordingly. Minimum operating hours (2 500 hours per year) are assumed for gas-fired plants to reflect the political incentives for gas-fired power generation.

The model uses 2015 as the base year and then iterates in five-year increments to assess potential policy impacts up to 2035. Initial national and provincial capacity and generation mixes are based on data from the China Electricity Council (CEC). After classifying coal- and gas-fired power plants into their subcategories, the capacity for each technology for the base year 2015 was verified by aggregating unit-level data and matching it with provincial data from the China Electricity Council (CEC). Uncategorised power units for which the technology cannot be identified are defined as follows:

- Gas-fired power units are considered as “below F-class”
- Coal-fired power units below 300 MW are classified as “high-pressure and ultra-high-pressure”
- Coal-fired power units above 300 MW are defined as “subcritical 300 MW”.

Total coal-fired power capacity in 2015 was 900 GW, made up of 17% ultra-supercritical, 20% supercritical 600 MW, 4% supercritical 300 MW, 11% subcritical 600 MW, 29% subcritical 300 MW, 13% high-pressure and ultra-high-pressure, and 5% CFB technologies. Total gas-fired power capacity in 2015 was 66 GW, with F-class accounting for 63% and below F-class making up 37%.

Investments in future power technologies are optimised, and units are assumed to retire upon reaching the end of their operational lifetime for most technologies. For coal-fired plants, a lifetime assumption of 30 years is made, and early retirement strategies can be activated when the fleet’s average running hours fall below a predefined threshold. Simulations for 2020 have been strongly calibrated based on 2020 statistics.

Technology and storage cost assumptions (Table A.3 and Table A.4) are based on several sources, including CEC data (CEC, 2016), *Cost of Electric Power Projects* (China, EPPEI and CREEI, 2017), *World Energy Outlook 2020* (IEA, 2020b), *China Power System Transformation* (IEA, 2019), studies on storage development (Liu et al. 2017; IRENA, 2017), and a National Renewable Energy

Laboratory (NREL) study (Vimmerstedt et al., 2019). The O&M costs for different technologies are adopted from the NREL report. This study makes the assumption that CCUS technology allows for the capture of 92% of plant emissions. Efficiency loss of CCUS-equipped plants is considered. Costs for CO_2 transport and storage, and liability or insurance costs for leakage from CO_2 storage facilities have not been taken into account.

Table A.3 Cost assumptions by technology

	Capital costs (CNY/W)			Variable O&M costs (CNY/MWh)	Fixed O&M costs (CNY/kW-yr)
	2015	2020	2035		
Coal	3.7-4.5	3.6	3.6	31	214
Coal with CCUS	23.6	23.6	12.8	58	449
Gas	2.7-3.1	2.6	2.6	23	96
Biomass	12	10.8	10.8	35	712
Nuclear	13.1	15.6	15.0	14	629
Hydro	7.5	10	10	0	203-268
Wind onshore	7.9	7.0	6.3	0	340
Wind offshore	20	15	11	0	881
Solar PV	8.1	5.3	2.8	0	106
CSP	-	29.8	22.4	27	438

Notes: CSP = concentrated solar power. Variable O&M costs in this table do not include fuel expenses or CO_2 cost, which are classified in the model as a separate cost component.

Table A.4 Cost assumptions by storage technology

	Capacity cost (CNY/Wh)		Variable O&M costs (CNY/MWh)		Fixed O&M costs (CNY/MW-yr)	discharging duration (hours)
	2020	2035	2020	2035		
Pumped hydro	0.5	0.5	1	1	45	8
Battery storage	1.5	0.775	14	11	25	4
Compressed air storage	0.33	0.275	20	20	1.5	20

The assumptions pertaining to coal and gas prices vary among China's regions. The regional coal prices for 2015 and 2020 are based on data from the China Coal Transportation and Distribution Association (CCTD) (Table A.5), while regional gas prices for 2015 and 2020 are based on the gate price for gas in China and on the IEA New Policies Scenario (NPS) Full flex case in *China Power System Transformation* (IEA, 2019). Average annual fuel price growth follows the World Energy Outlook (WEO) STEPS (IEA, 2020b). Coal prices in Xinjiang, Eastern Inner Mongolia and Western Inner Mongolia are the lowest, followed by Ningxia and Shanxi, while in other regions they are relatively high and can be more than double the Xinjiang price. Gas prices in Xinjiang and Qinghai are relatively low compared with other regions of China.

Table A.5 Coal price assumptions by area, 2020

Region	Coal price in 2020 (CNY/GJ)
Xinjiang	12
Eastern Inner Mongolia	12
Western Inner Mongolia	13
Ningxia	17
Shanxi	17
Others	≥21

The transmission cost contains two components: transmission line installation costs and O&M costs. The cost of installing transmission lines between two regions includes set costs related to capacity (CNY 1.5 million/MW, USD 0.23 million/MW) and to distance (CNY 1 000/MW per km, (USD 155/MW per km). The annual O&M cost is set at 3% of the transmission line installation cost.

The model includes energy efficiency measures as one lever for reducing CO_2 emissions. The costs for CO_2 emission reduction from energy efficiency are shown in Table A.6, which are set at three levels for each technology.

Table A.6 Assumptions on emissions reduction costs from energy efficiency measures

	Level 1 (CNY/t CO_2)	Level 2 (CNY/t CO_2)	Level 3 (CNY/t CO_2)
CFB	355	369	383
High-pressure	342	355	369
Subcritical-300MW	363	377	391
Subcritical-600MW	396	410	424
Supercritical-300MW	369	383	396
Supercritical-600MW	410	424	437
Ultra-supercritical	410-465	437-478	451-492
Gas	2 175-2 275	2 200-2 300	2 225-2 325

The RPS policy is included as the main policy driver for renewables deployment, and is modelled by a generation constraint where the share of electricity from non-hydro renewables in the total demand should be no less than the required target. This analysis assumes the non-hydro renewables share target to be 25.9% by 2030 and 36% by 2035, based on NEA’s consultation draft on indicative RPS targets for 2022-2030 (China, NEA, 2021a), and the assumption of a moderate acceleration in annual target increase for 2031-2035 (Table A.7).

Table A.7 Assumptions for the non-hydro renewables share target under the RPS policy

	2025	2030	2035
Non-hydro RPS	18.6%	25.9%	36.0%

For hydro (excluding pumped hydro), a capacity range is assumed that increases moderately over time. Nuclear capacity is assumed to more than double by 2035, in line with the pace of capacity installations in the past five years and plans up to 2025.

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Abbreviations and acronyms

APS	Announced Pledges Scenario
BM	Benchmark
CCER	Chinese Certified Emissions Reduction
CCUS	Carbon capture, Utilisation and Storage
CEC	China Electricity Council
CFB	Circulating Fluidised Bed
CO_2	Carbon Dioxide
CSP	Concentrated Solar Power
ETS	Emissions Trading System
EU	European Union
FIT	Feed-In Tariff
FYP	Five-Year Plan
GDP	Gross Domestic Product
GHG	Greenhouse Gas
IEA	International Energy Agency
MEE	Ministry of Ecology and Environment
MSR	Market Stability Reserve
NDC	Nationally Determined Contributions
NDRC	National Development and Reform Commission
NEA	National Energy Administration
NPS	New Policies Scenario
NREL	National Renewable Energy Laboratory
O&M	Operation and Maintenance
PV	Photovoltaic
REPO	Renewable Electricity Planning and Operation
RPS	Renewable Portfolio Standards
STEPS	Stated Policies Scenario
TPS	Tradable Performance Standard
VRE	Variable Renewable Energy
WEO	World Energy Outlook

Glossary

Gt	Gigatonne
CNY	Chinese Yuan Renminbi
USD	US dollars
gce/kWh	Gramme of standard coal equivalent per kilowatt hour
GW	Gigawatt
GJ	Gigajoule
MW	Megawatt
MWh	Megawatt hour

TWh	Terawatt hour
kg	Kilogramme
kWh	Kilowatt hour
Mt	Million tonnes
t	Tonne

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