Balancing Act: Stranded Assets and Flexibility in China's Power Sector

Analyst Note

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About Carbon Tracker

The Carbon Tracker Initiative is a team of financial specialists making climate risk real in today's capital markets. Our research to date on unburnable carbon and stranded assets has started a new debate on how to align the financial system in the transition to a low-carbon economy.

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1 Key Findings and Recommendations

In September 2020, the People's Republic of China announced targets of peaking economy-wide carbon emissions before 2030 and achieving carbon neutrality before 2060. With national emissions equivalent to approximately one-third of the global total, these commitments are some of the most significant ever made in the global response to climate change. China's power generation is approximately 60% reliant on thermal power, the majority of which is coal-fired. To achieve its climate targets, China must therefore transition away from a reliance on coal towards low-carbon alternatives. China has led the world in the deployment of wind and solar, bolstered by the strong financial case for renewables over coal. However, recent data indicates that c.200 GW of new coal capacity is currently under construction or in various stages of permitting, with 50GW beginning construction in 2022 alone[i]. If all planned units are completed, they will join a fleet already suffering financial stress and are unlikely to recover investment costs over their operating lives. The poor financials indicate that the motivation for these investments is to ensure security of supply, driven by a series of supply crises during 2021-2022, but the scale of planned capacity additions is at odds with China's stated emissions targets, particularly if these plants operate as baseload generation.

- China's planned investments in over 200GW of new coal capacity could lead to between US$26-US$40bn of value destruction via asset stranding. Allowing all planned units to be completed entails significant financial risks and could increase the costs of timely power sector decarbonisation.

  To reduce stranding risk, all planned coal units not absolutely critical for grid balancing or district heating should be cancelled or mothballed. Stated commitments to prevent the construction of additional baseload coal capacity should be more stringently enforced.

- Existing grid management and power trading arrangements entrench incentives for provincial governments to invest in local thermal capacity to meet growth and volatility in power demand. The prevalence of inflexible, long-term power trading arrangements inhibits more dynamic regional transfers, pushing local energy planners towards investments in local coal to ensure security of supply.

  Facilitating more price discovery and flexible inter-provincial trading should be a key near-term priority of ongoing power market reforms. Expanding channels for shorter-term power trading and flexibility, such as via interprovincial spot markets, could unlock latent potential in China's grid and reduce incentives for new coal investments.

- Technological retrofitting of coal units for greater flexibility could have significant positive implications for emissions reductions, renewables integration and system stability. However, it is unclear that sufficient economic incentives always exist for coal plants to invest in technologies that enable a transition from baseload to flexible generation.

  The potential emissions reductions and improved system value achieved through the technological retrofitting program warrants its expansion to all feasible units. Out-of-market revenues from expanded ancillary service markets and the implementation of competitive capacity markets should be prioritised to provide greater financial incentives for operating coal units to transition to more flexible roles, expediting the decline of baseload coal and power sector emissions.

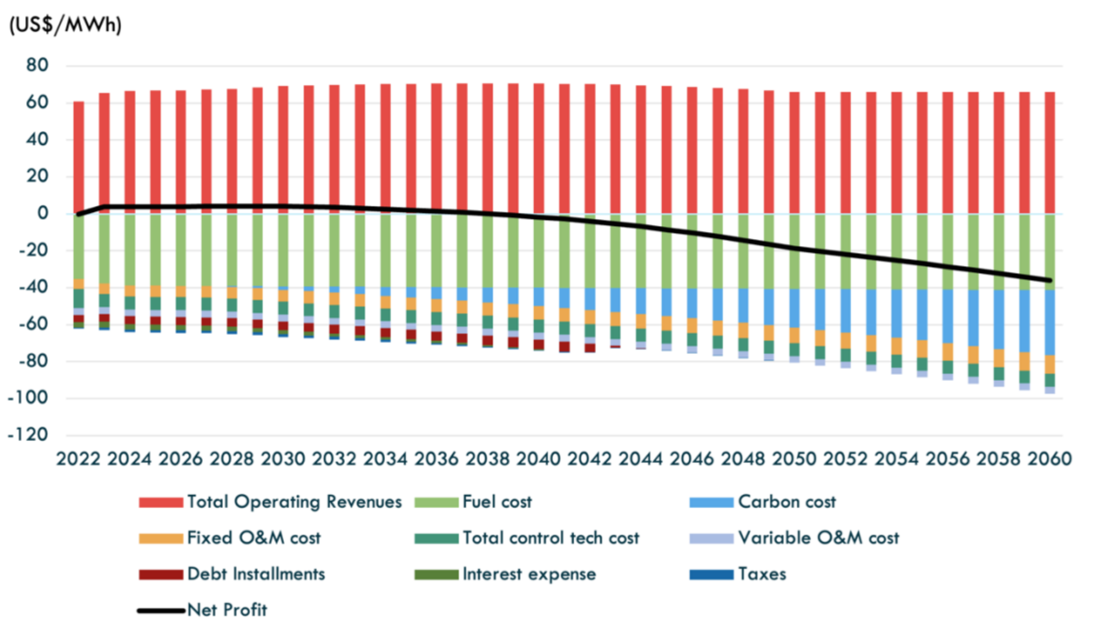
2 Introduction

Given natural operating lives spanning 30-40 years, achieving a timely power sector decarbonisation will require that the vast majority of China's planned coal units to be retired early or see utilisation rates decline to financially unviable levels. This means that China's planned coal investments risk becoming 'stranded' when project revenues are insufficient to recover investment costs. This note aims to assess the financial risks in these investments and offer high-level recommendations for minimising future financial losses and avoiding increases in carbon emissions. We have conducted asset-level project finance modelling considering the operating profits, debt financing obligations and tax expenses of all upcoming coal units. Using the asset level financial data, we have quantified the stranded asset balances likely to be incurred by the coal pipeline under multiple phaseout scenarios consistent with domestic and international climate goals. Our modelling indicates that these investments could lead to between US$26-40bn of value destruction through asset stranding. Allowing these projects to begin operations will therefore increase the costs and challenges of implementing a timely power sector decarbonisation.

The recent increase in coal investments come off the back of a tumultuous period in China's power sector. In 2021, sharp increases in domestic coal prices placed the coal fleet under severe operational pressure, contributing to a series of blackouts as many coal plants refused to generate when unable to recover operating costs. This was followed by an extreme heat wave in 2022, leading to unprecedented spikes in power demand and the subsequent implementation of curbs on power consumption. The response to these events has been market interventions to constrain coal prices and a renewed focus on implementing power market reform to relieve the coal fleet of financial stress. However, this has also been accompanied by huge new investments in coal capacity which can be called upon to meet future jumps in peak demand and avoid repetitions of the events in 2021-2022.

We believe that increasing coal capacity at the scale currently planned represents a financially wasteful approach to satisfying forecast growth in power demand and managing future volatility in peak loads. New coal capacity would be joining a fleet that already faces strained profit margins due to high fuel prices. Rising carbon prices associated with the implementation of the national ETS would also steadily erode what are currently slim or negative profits. Returning the fleet to profitability under current market structures would require a significant increase in power prices to pass commodity and carbon costs onto the real economy. This would in turn place pressure on domestic energy-intensive industries which have historically been the backbone of Chinese economic growth.

FIGURE 1: AGGREGATE CASHFLOW AND NET PROFIT – PLANNED COAL UNITS



Source: Carbon Tracker

These new coal investments are also coming at a time when declines in the costs of renewable alternatives have already passed key economic inflection points. Our analysis indicates that, for almost all technologies, and in almost every major grid region in China, the levelized costs of wind and solar power are now below the levelized costs of new coal power. This means that China's planned coal plants could be cancelled and replaced with renewables without incurring financial losses.

These favourable economics underpin the enormous progress that China has made in terms of rolling out renewable capacity, which has been unmatched globally. In 2022 alone, China added 122GW of wind and solar and, according to the IEA, these clean energy investments were 11 times greater than investments in coal power, despite the significant growth in coal investments[ii]. In terms of power generation, renewables account for roughly 15% of total power generation, versus around 60% figure for coal.

Although changes in relative economics now tilt firmly in favour of renewables over coal, China's renewable power generation is concentrated in the central and northern grid regions, whereas the largest sources of power demand are located along the southern and eastern coasts. Transporting this power comes with significant challenges and is currently beset by many technological and regulatory constraints. These challenges are used as non-financial justifications for increasing local coal capacity, which can be dispatched quickly to balance the grid. The desire to ensure security of supply after the events of 2021-2022 is also undoubtedly a core driver of the recent expansion of coal investments, with some provinces mandating the construction of new coal capacity to support renewable generation[iii].

This situation is exacerbated by an approach to grid management that is not conducive to interregional trading, utilisation of storage capacity and a low-carbon power system. Most cross-regional trading in China is still determined on the basis on mid- to long-term, pre-agreed quotas. This creates a fragility in China's power system, meaning that it struggles to respond quickly to short term imbalances in supply and demand. In addition, regional differences in power pricing can inhibit interregional trading, as provincial grids may be reluctant to import power at higher prices. Taken together, this means that the incentives to ensure that local generation is sufficient to cover future spikes in power demand become entrenched.

Promoting more dynamic power trading to unlock some latent potential in China's grid should therefore be a top near-term priority in ongoing power sector reforms. As part of long-term reform efforts to modernise the power system, China has experimented with intra-provincial power spot markets. In broader efforts to create a 'Nationally Unified Power Market', in July 2022, the first inter-provincial power market began trial operations in China's southern grid region, however trading volumes in all spot markets is relatively low. Expanding these channels for dynamic, short-term trading will become increasingly important to balance the variability associated with more renewable generation.

Aside from flexibility in grid management and trading, another key factor in expediting power sector decarbonisation is flexibility in dispatchable generation to ensure growing renewables can be maximally utilised. With little installed gas capacity, China is left with coal as its main source of flexible power. Under current market structures, the main financial incentive for coal plants is to operate at higher baseload utilisation rates to increase revenues in longer term wholesale markets, which hinders renewables integration and increases aggregate carbon emissions. Despite prior commitments to prohibit the construction of new baseload capacity, permitting documents from many upcoming units indicate an intention to operate as baseload[iv]. This is compounded by the fact that most coal units are not designed to operate flexibly, which has contributed to high renewables curtailment in the past.

Recognising the need for greater flexibility, China implemented a program to retrofit operating coal capacity for greater flexibility and efficiency, with a retrofit target of 200GW by 2025. These efforts have significant financial and environmental implications, due to flexible operations implying decreases in average utilisation rates and carbon emissions. The significance of these potential emissions reductions warrants the expansion of the program to all coal units for which it is technically feasible. However, it is not clear that sufficient financial incentives always exist for plants to willingly implement these changes, given the high capital costs and opportunity costs associated with retrofitting.

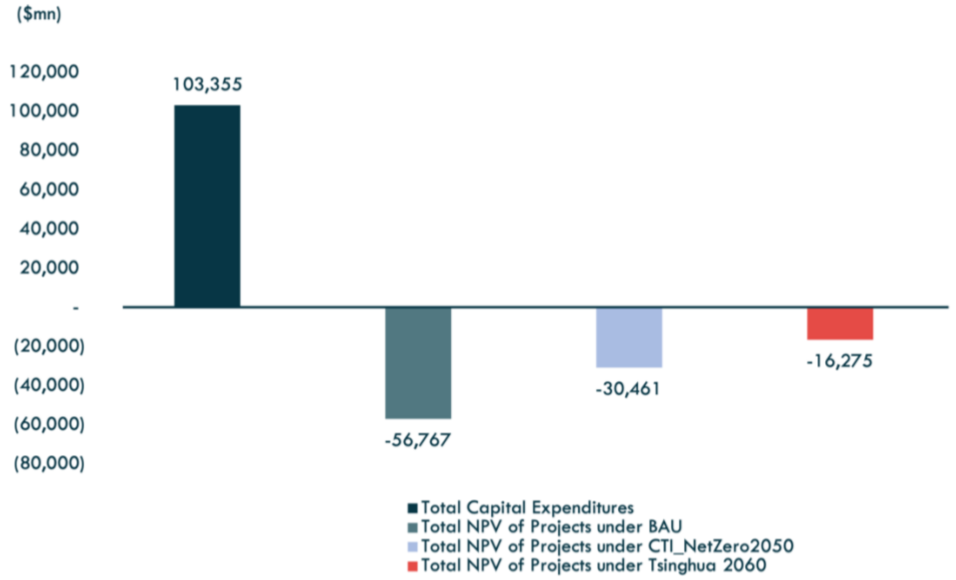
Market reforms, such as the expansion of ancillary service markets, have created some out-of-market incentives for flexible generation, which have helped to address renewables curtailment. These markets could also encourage greater utilisation of storage capacity to replace coal as the provider of grid balancing in the medium term. Policymakers should expand these out-of-market revenue schemes to make flexible operations an economically attractive alternative to baseload. Competitive capacity markets should be explored as a means of helping flexible units cover fixed costs and opportunity costs from forgone wholesale power revenues as they transition away from baseload. In developing all market-based schemes, China should avoid a piecemeal approach and focus on coordination and integration, particularly at the regional level. This would help avoided unintended consequences, such as incumbent coal generators exploiting market power to influence the direction of reforms in ways that benefit coal over renewables.

3 Asset Stranding Risk in China's Upcoming Coal Pipeline

3.1 China's coal pipeline risks US$26-US$40bn of value destruction through asset stranding

According to data from Global Energy Monitor[v], as of January 2023, China has 317 coal plants under construction or in various stages of permitting, amounting to approximately 200GW of capacity and US$100bn of capital expenditures. To assess the financial implications of these investments, we compare each asset's net present value[vi] (NPV) in a business-as-usual (BAU) scenario, whereby coal assets operate to the end of their useful lives, with the NPV in an emissions-constrained scenario where coal plants are forced into early retirement so that finite carbon budgets are not exceeded. Using these emissions constraints, we develop phaseout schedules specifying the year in which each coal plant must be retired to prevent coal power emissions rising above unsafe levels, prioritising units for early phaseout based on costs, grid location and plant type[vii]. To model NPVs in the climate-constrained scenarios, we use Carbon Tracker's NetZero by 2050[viii] scenario, which sees unabated coal generation capacity phased-out by 2040 and is consistent with approximately 1.5 degrees of global average temperature increases. We also use Tsinghua University's 2060 Carbon Neutrality scenario, which is consistent with China's stated targets of peaking emissions before 2030 and achieving carbon neutrality by 2060, seeing unabated coal use in the power sector eliminated by 2050[ix]. Comparisons of the upcoming fleets' expected financial performance in each of these scenarios allows the calculation of stranded asset balances[x].

FIGURE 2: CAPITAL EXPENDITURES & NPVS IN BAU VS CLIMATE ALIGNED SCENARIOS – ALL PLANNED COAL UNITS



Source: Carbon Tracker Data

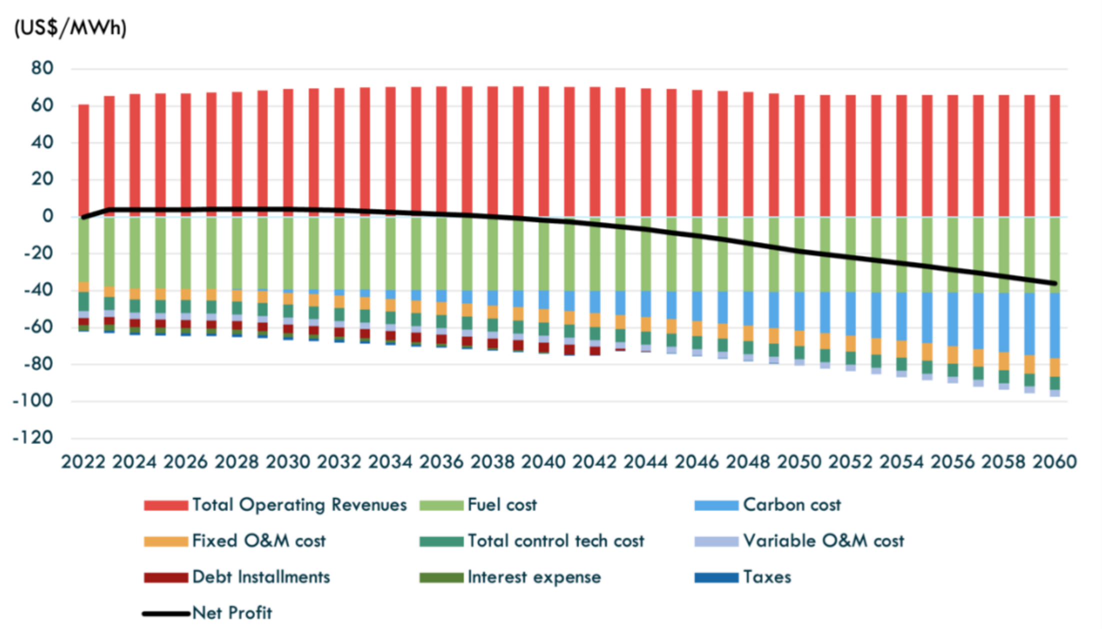
Our modelling indicates that, if all 200GW of upcoming coal capacity is added to the grid, these coal plants will return a negative NPV of approximately US$57bn in a BAU scenario. Under the climate-constrained scenarios where coal plants are forced to close early, the negative NPVs of China's planned coal projects could be reduced to between US$30bn and US$16bn in CTI NetZero and Tsinghua 2060, respectively. The fact that the BAU scenario incurs a more severe negative NPV than in the climate-constrained scenarios reflects the expectation that many planned coal plants in China will either begin operations as loss-making units or become unprofitable over time if allowed to reach the end of their natural operating lives.

In markets where power plants are expected to generate positive returns, but future profits are foregone upon early closure, investors will incur a 'positive' stranded asset balance because the NPV in BAU is greater than the NPV under a climate-aligned phaseout. By contrast, because most planned coal plants in China are expected to be unprofitable over their natural operating lives, financial losses are smaller if these plants are retired earlier under climate-aligned phaseouts. As such, China's coal pipeline risks becoming 'negatively' stranded by US$26bn and US$40bn in CTI NetZero and Tsinghua 2060, respectively.

The difference in stranding risk in CTI NZE and Tsinghua 2060 reflects the different dates at which coal phaseouts begin under the two scenarios. In CTI NZE, coal phaseouts in China begin immediately in 2023; in the Tsinghua 2060 scenario, coal phaseouts do not begin until 2030. Whilst the financials of China's planned coal plants are currently fragile, our modelling indicates that the fleet's financials begin deteriorating more rapidly in the mid 2030s (more on this below). As such, the later phaseout date under Tsinghua 2060 initially allows more time in the mid to late 2020s for some units to pay off investment costs, explaining the smaller losses in Tsinghua 2060 vs CTI NZE. However, the point to emphasise is that, according to the IEA's modelling, coal phaseouts consistent with safe levels of global temperature increases must begin sooner than 2030 which, together with the significant negative stranding risk, highlights the financial and environmental incentives to constrain these new investments in coal capacity.

Beginning in 2021, rapid and sustained increases in domestic coal prices, coupled with an inflexible power pricing mechanism, meant that many coal generators were left unable to recover increased costs. These events contributed to a series of power outages beginning in 2021, with many plants refusing to operate. In response, regulators have implemented semi-marketised coal power pricing (with tariffs that can float +/- 20% around fixed provincial benchmarks), mandated that energy-intensive consumers procure power in competitive wholesale markets and imposed caps on domestic coal prices[xi]. These interventions have been effective in reducing some of the pressures faced by coal generators, however many coal plants in China still struggle to break even. Despite these losses, 50GW of capacity began construction in 2022, representing an increase of over 50% relative to 2021[xii].

FIGURE 3: AGGREGATE CASHFLOWS AND NET PROFIT – PLANNED COAL UNITS (US$/MWH)



Source: Carbon Tracker Data

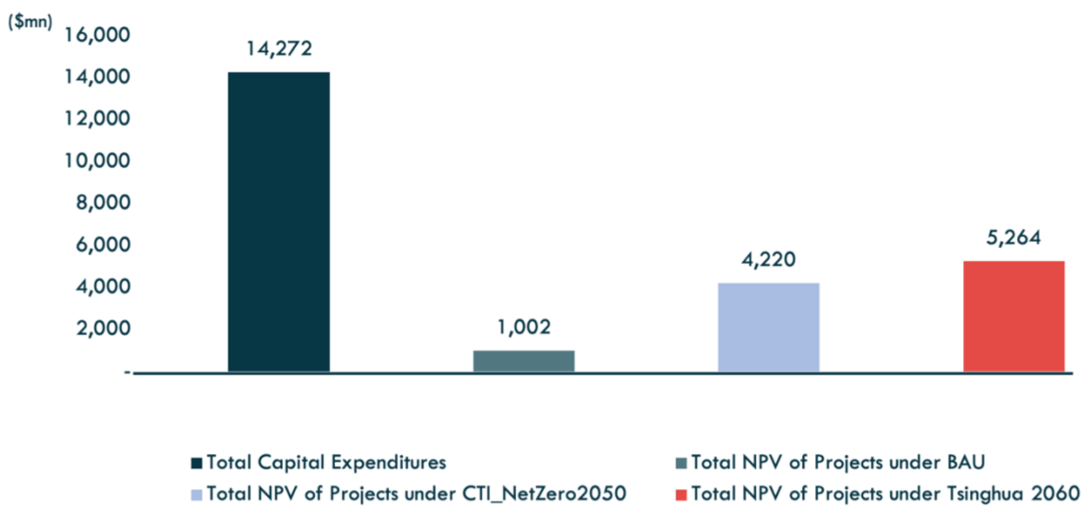
In particular, the long-term unprofitability is driven by an increased presence of renewable generation forcing coal utilisation rates (and therefore power sales) lower, whilst rising carbon costs associated with the 2021 implementation of the nationwide emissions trading scheme erode plant margins[xiii]. Though the relative economics of coal units differs significantly by grid region, declines in capacity factors and rising carbon prices will be sufficient to flip the upcoming coal pipeline's aggregate net profits negative before 2040. As such, coal generators would become increasingly dependent on market interventions and soft budget constraints provided by state-owned banks; to operate profitably under current market structures would require a significant increase in power prices to pass high commodity and carbon costs through into the real economy. This would in turn place pressure on domestic energy-intensive manufacturing industries which have historically been the backbone of the Chinese economic growth.

These data lay plain the profit motive that exists for China to reduce the extent of these potential losses by reducing the upcoming coal pipeline. We recognise the necessity of firm power reserves in ensuring grid stability and security of supply. However, in the absence of a clearly defined phaseout strategy, the scale of potential upcoming coal investments could unnecessarily increase carbon emissions and expend limited financial capital which could otherwise be deployed in investments consistent with China's stated power sector decarbonisation targets, such as flexible generation, transmission, and storage.

3.2 Combined heat and power plants guaranteed modest returns

For this report, we implemented a separate modelling treatment for combined heat and power plants (CHPs), which comprises approximately 15% of the planned pipeline at 30GW. CHP units, also known as cogeneration units, capture heat produced when coal is combusted in power generation which, in the case of power generating units, is otherwise wasted. In China, most CHP units are located in the northern regions which face cold winters, with the heat captured and sold for use in district heating. The sale of both electricity and heat means that CHP units have additional revenue streams compared to plants which only generate power. Moreover, the fact that renewable technologies such as wind and solar PVs generally do not provide heat means that, in many cases, renewable technologies cannot directly substitute for the role of coal CHP units. Finally, whilst China has been introducing power sector reforms to the dispatching and pricing of coal power, the social importance of district heating means that CHP units are regarded as 'must-run' in the winter, often enjoying priority dispatch and being compensated on a cost-plus basis, meaning that a modest return is effectively guaranteed under the current policy environment[xiv]. To reflect these facts, we have included additional revenue streams from heat sales priced at provincial benchmark heat tariffs, adjusted our capacity factor scenario to account for their 'must-run' status and prioritise power units for early phaseouts over CHPs.

FIGURE 4: CAPITAL EXPENDITURES & NPVS IN BAU VS CLIMATE ALIGNED SCENARIOS – ALL PLANNED CHP UNITS (US$MN)



Source: Carbon Tracker Data

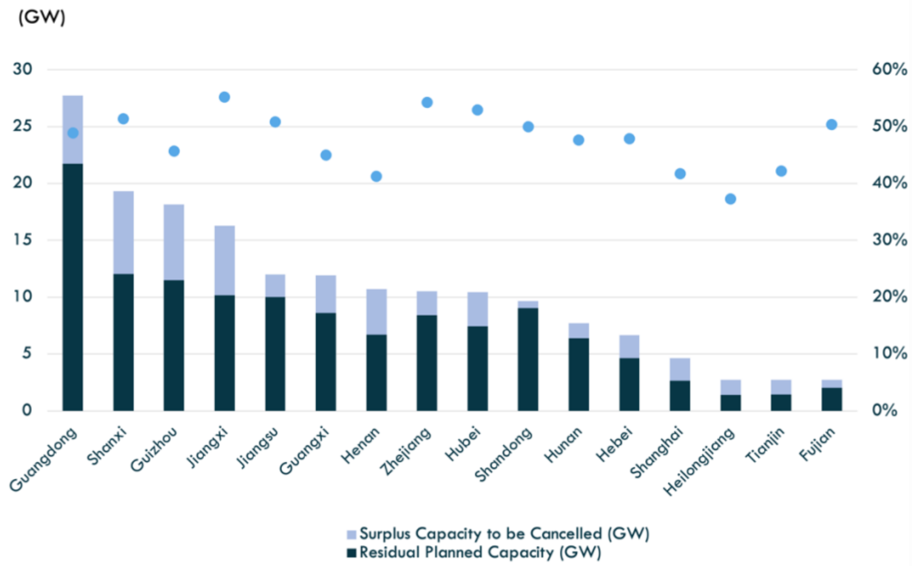
Relative to capital expenditures of c.US$14bn, China's planned CHP fleet will return a positive NPV of US$1bn in a BAU scenario, increasing to US$4.2bn and US$5.2bn in CTI NetZero and Tsinghua 2060, respectively. The positive NPV balances in all scenarios are due to both the additional revenue streams from the sale of heat, as well as the assignment of later phaseout dates relative to power units, meaning that CHP plants have longer operating lives in which to earn back investment costs. However, the larger NPV balance in the climate-aligned scenarios (and therefore negative stranding risk) again reflects the expectations of rising carbon prices rise as China nears its decarbonisation targets. Although CHPs are currently remunerated on a cost-plus basis, under current market structures, these compensation mechanisms are not sufficiently flexible to transmit higher carbon costs onto consumers. This means that many of the least efficient CHP units would be forced to absorb these increased carbon costs, becoming loss-making towards the end of the natural operating lives. Shutting these plants down early could avert some of the forecast financial losses, resulting in larger NPVs under managed phaseouts scenarios. Importantly, many CHP plants in China are designed to either generate both heat and power simultaneously, or just generate power[xv]. For both environmental and financial reasons, it is therefore important that CHP capacity additions are not used as a guise to increase coal capacity intended purely for baseload power generation.

3.3 China's coal expansion at odds with previous statements to prohibit new baseload coal

The poor expected financial performance of the upcoming fleet means it is likely that the core motivation for the expansion in coal investments is the desire of provincial governments to avoid a recurrence of severe power supply shortages that occurred nationwide over the past two years (more below). In 2019, a Director at China Electricity Council stated that up to 150GW of coal capacity could be added in the 14th Five Year Plan period[xvi], emphasising the need for dispatchable reserves in grid balancing as renewable generation increases. In 2021 these statements were reiterated by the State Grid Energy Research Institute[xvii]. Moreover, the National Energy Administration stated in 2022 that coal capacity additions intended purely for baseload generation should 'in principle' not be approved for permitting[xviii].

Plants used mainly for grid balancing would imply significantly lower capacity factors (and emissions) compared to baseload plants. However, permitting documents indicate that many pipeline units intend to operate at baseload utilisation rates[xix]; the 200GW of planned capacity is also materially above the maximum estimated capacity needed for balancing renewables. Taken together with the poor expected financial returns, it is possible that many of these units will ultimately be mothballed or cancelled, particularly plants not deemed necessarily for grid flexibility or district heating and which are still in the earlier stages of permitting[xx]. According to our analysis, eliminating 50GW of non-CHP units with the lowest expected profitability, located in provinces already suffering the lowest utilisation rates, and which have yet to complete the permitting process, could reduce potential asset stranding by approximately US$8.5bn and US$10.5bn in CTI NetZero and Tsinghua 2060, respectively.

FIGURE 5: CAPACITY SURPLUS TO FORECASTED GRID-BALANCING NEEDS



Source: Carbon Tracker & Global Energy Monitor Data

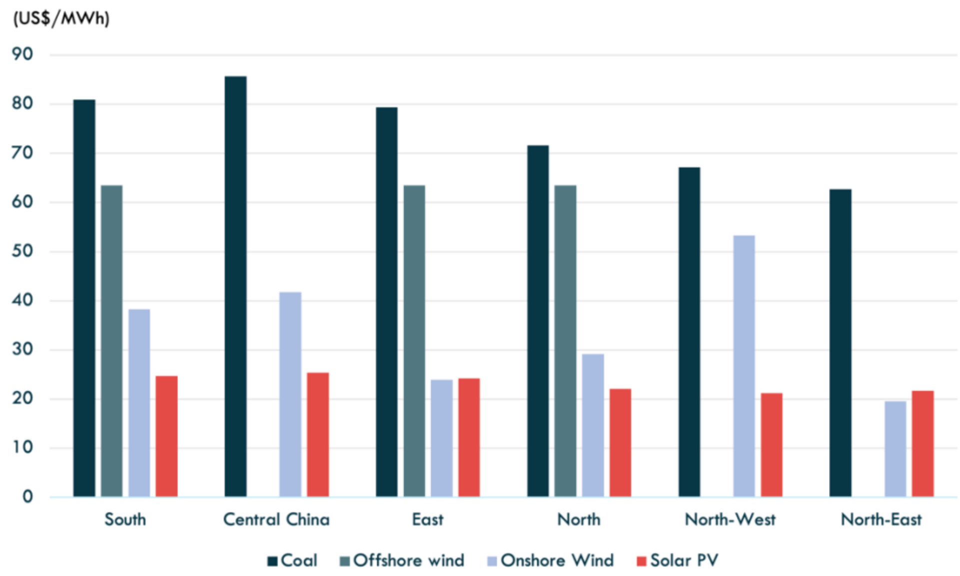
These cancellations would constitute the most cost-effective means of reducing planned capacity additions to comply with previously stated estimates for the maximum capacity needed for grid stability. This said, under current pricing mechanisms, the financial incentives for completed projects would be to maximise generation, which would be detrimental to the integration of renewables and increase carbon emissions. The commitments to prohibit new baseload capacity should therefore be more stringently enforced, with all planned capacity surplus to levels needed for grid balancing or district heating cancelled or mothballed.

3.4 Declines in costs of renewables have eliminated financial justifications for new coal capacity

These coal capacity additions are coming at a time when the relative economics of coal versus renewables in China have already surpassed key economic inflection points. Whilst limitations of the levelized cost of energy metric (LCOE) are well-documented, an LCOE analysis can provide a simple proxy for observing changes in the relative economics and capital costs of power generation assets over time. Putting grid constraints aside, when the LCOE of renewable technology falls below the LCOE of coal, it is cheaper to build new renewables projects than it is to build new coal plants. For this analysis, we have modelled the unsubsidised LCOEs of wind and solar projects in each of China's major grid regions and compared these to the regional LCOEs of new coal power. Due to China's size and significant geographical disparities, the capacity factors (and therefore LCOEs) of renewable technologies differ markedly by region, particularly for wind power. Similarly, due to differences in local resource endowments, Chinese regions see significant differences in fuel prices, with coal plants in the Central, Eastern and Southern regions incurring higher costs due to the need to pay larger transportation fees.

A full table illustrating the LCOEs of renewables versus the costs of new coal power can be found in the appendix to this report. However, in summary, our analysis indicates that, for almost all renewable technologies, and in almost every major grid region in China, the LCOEs of renewables are now below the LCOE of new coal power. Due to the regional differences in fuel costs, the LCOE of coal power ranges from US$63/MWh in the North-east to US$86/MWh in Central China. Even at the lower bounds, declines in the levelized costs of onshore wind and offshore wind (where applicable) mean that, in every major grid region, it is now materially cheaper to build these technologies than it is to build new coal. These cost differences are largest for Solar PV, which is now on average US$51/MWh cheaper than coal on an LCOE basis. Onshore wind is similarly cost-competitive, with average LCOEs now US$40/MWh lower than coal. The exception in North-western China, where lower regional coal prices and wind speeds mean that the average cost gap between onshore wind and coal is reduced to US$14/MWh.

FIGURE 6: RENEWABLE LCOE VS COAL LCOE IN CHINESE GRID REGIONS



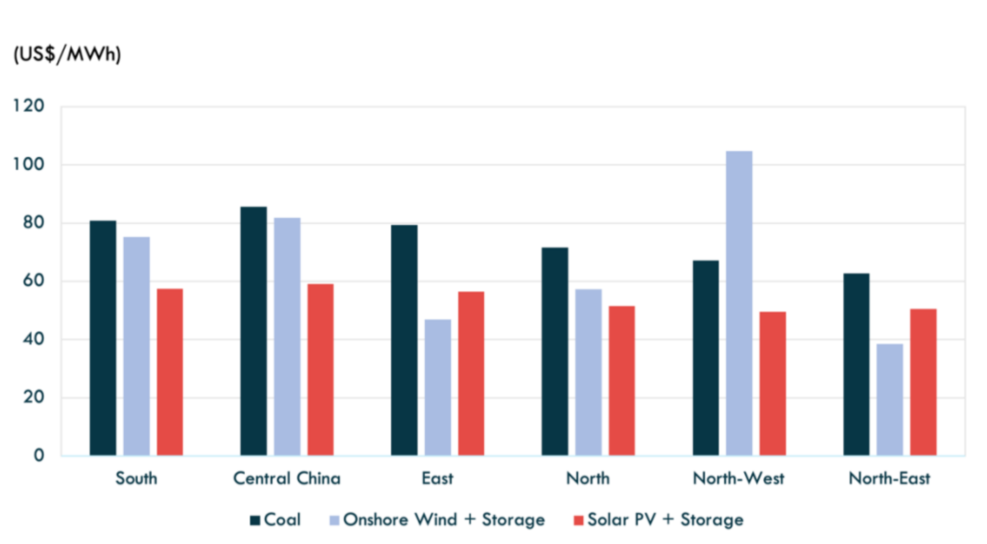
Source: Carbon Tracker Data

For the grid regions in China that are not land-locked, we model the LCOEs of offshore wind versus coal. Compared to onshore wind, the greater complexity involved in constructing offshore wind turbines means that these assets incur higher capital costs, especially when sited in deeper waters further from the shores. Despite the higher capital costs, offshore wind is now on average US$14/MWh cheaper than new coal on a levelized basis. We compare the average LCOEs of offshore wind and new coal at the regional level, however reports show that specific offshore wind projects are already achieving grid-parity with coal in select provinces. For example, a notice published in late 2022 by the National Energy Administration in Shandong Province[xxi] reported that a 500MW offshore wind farm was connected to the grid at an LCOE equivalent to US$57/MWh, roughly equal to the on-grid tariff for coal power in the province. These cost declines demonstrate that, even when compared to the most expensive renewable technologies, the financial justifications for investing in new coal capacity have been eliminated.

The challenges of integrating variable power into the grid often mean that increasing capacity of fuels such as coal, nuclear and gas is justified by the need to ensure sufficient reserves of dispatchable power for grid stability. However, even accounting for the increased capital costs associated with building renewables with on-site storage (which approximately doubles the LCOE), these technologies have still passed the key economic inflection points discussed above. Building solar with storage is now on average US$20/MWh cheaper than building new coal on a levelized basis; for onshore wind, coupling projects with storage works out $7/MWh cheaper on average compared to coal.

In our modelling, we incorporate cost assumptions sufficient to provide a storage duration of four hours. For solar power, the higher regularity in utilisation rates means that developers can install on-site batteries which store power generated in the mid- and later parts of the day for use in meeting rising demand in the evening, improving project economics. By contrast, larger irregularities in wind speeds, which can often remain low for days or even weeks, helps explain why the economics of building onshore wind with storage are less favourable than for solar projects. Moreover, it is important to highlight that building renewables with on-site storage often still faces technological challenges and market barriers, particularly when deployed at scale, meaning that specific project economics may deviate from the LCOEs. These issues are discussed in more depth in Section 2.

FIGURE 7: RENEWABLE + STORAGE LCOE VS COAL LCOE IN CHINESE GRID REGIONS



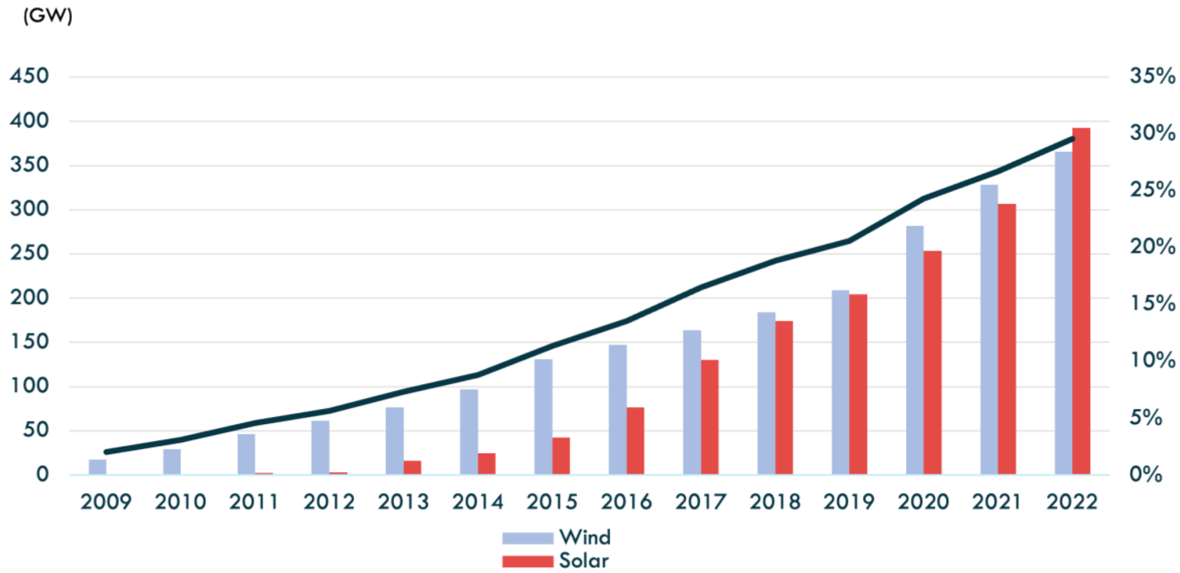
Source: Carbon Tracker Data

As mentioned in the previous section, sharp increases in domestic fuel prices beginning in 2021 have significantly increased the costs of coal power in every Chinese region; it is possible that future declines in domestic coal prices could narrow the cost gap between coal and renewables. However, even assuming some moderation in future fuel costs, the extent of declines in the costs of renewables means that the key economic inflections points discussed above are unlikely to reverse. This means that China's planned coal units which are yet to begin construction could be cancelled and replaced with a renewable alternative without incurring financial losses.

3.5 China's renewables buildout unmatched globally

The favourable economics of renewables versus coal underpin the enormous progress that China has made in terms of rolling out renewables. Between 2009-2022, total installed wind capacity grew from 17GW to 365GW; over the same period, total installed solar capacity grew from a negligible base to 392GW. This has meant that wind and solar now account for approximately 30% of China's total installed capacity. In 2022 alone, China added 122GW of wind and solar capacity and, according to the IEA, clean energy investments in 2022 were 11 times greater than China's investments in coal power, despite the significant increase in coal investments[xxii]. In terms of power generation, which is the relevant metric from the perspective of CO2 emissions, owing to the significantly lower average utilisation rates of wind and solar power compared to nuclear and thermal, renewable power accounted for approximately 13% of total power generation in 2022. By contrast, thermal power generation (the vast majority of which is coal-fired) accounted for over 60% of total power generation. Although this proportion has declined materially over the past decade, these data make clear that coal is still far and away the largest source of power in China's grid, a situation which could be exacerbated by the planned coal capacity additions discussed above. These data illustrate the challenges still ahead for China in decarbonising the power sector, but an encouraging observation is that growth in power generation from wind and solar accounted for over half of the 3.2% growth in total power demand in 2022[xxiii], implying that China is approaching the point at which renewable generation growth can alone meet forecast increases power demand.

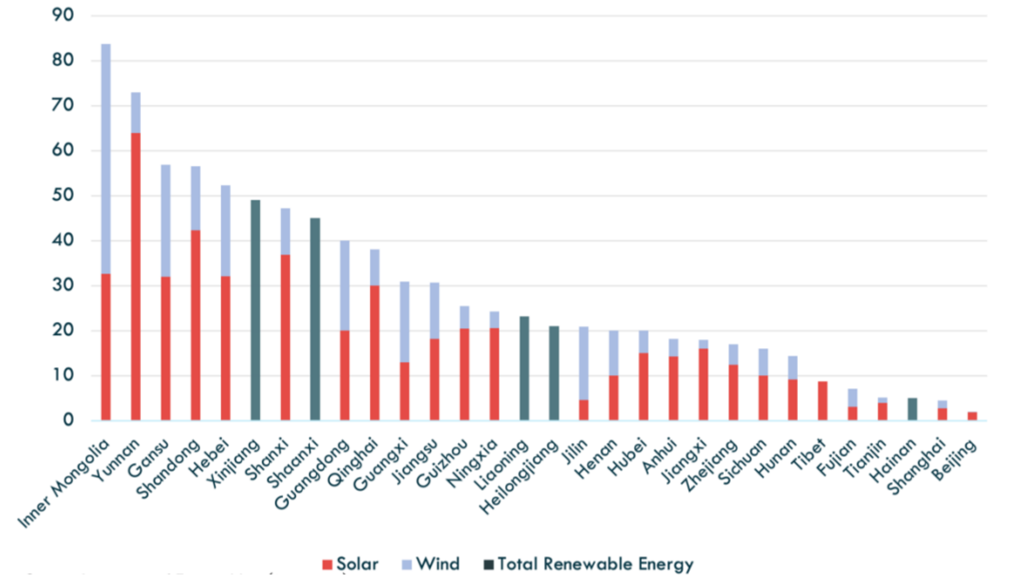
FIGURE 8: CHINA'S INSTALLED WIND AND SOLAR CAPACITY



Source: Wind fInancial Terminal

Fortunately, China is also endowed with enormous technical potential for renewable energy. Even in light of the huge capacity additions in the last decade, current installed capacity for wind and solar stand at just 13% and 14% of total technical potential, respectively[xxiv]. If all the renewable capacity additions proposed by China's various provinces over the 14th FYP period come to fruition, this would see an additional 329GW and 545GW of wind and solar added to China's grid[xxv]. This would still only increase the share of each of these technologies to 24% and 35% of maximum technical potential, respectively.

FIGURE 9: CHINA 14TH FYP PROVINCIAL WIND AND SOLAR CAPACITY ADDITION TARGETS (GW)



Source: International Energy Net (in-en.com)

The Northern, Central and Western provinces in China, such as Inner Mongolia, Xinjiang and Gansu, have the most ambitious capacity roll-out targets given the larger availability of open land; moreover, siting renewable assets in these regions is beneficial from the perspective of maximising utilisation given above average solar irradiance and wind speeds (with the exception of the North-Western region, which has below average wind utilisation rates). Concentrating capacity additions in these regions brings clear cost advantages, however the fact that China's load centres are located in the large urban centres along the Southern and Eastern coast means that integrating and transporting the variable power from the source of generation to the source of demand comes with significant technological and regulatory challenges. Of the total expected renewable capacity additions in these bases, 150GW has been earmarked for long-distance transmission to China's load centres [xxvi]. Resolving these bottlenecks will become an increasingly pressing concern as China continues to ramp up renewable capacity additions in these regions. Failure to do so could potentially limit the extent to which generation from the new capacity can be fully utilised.

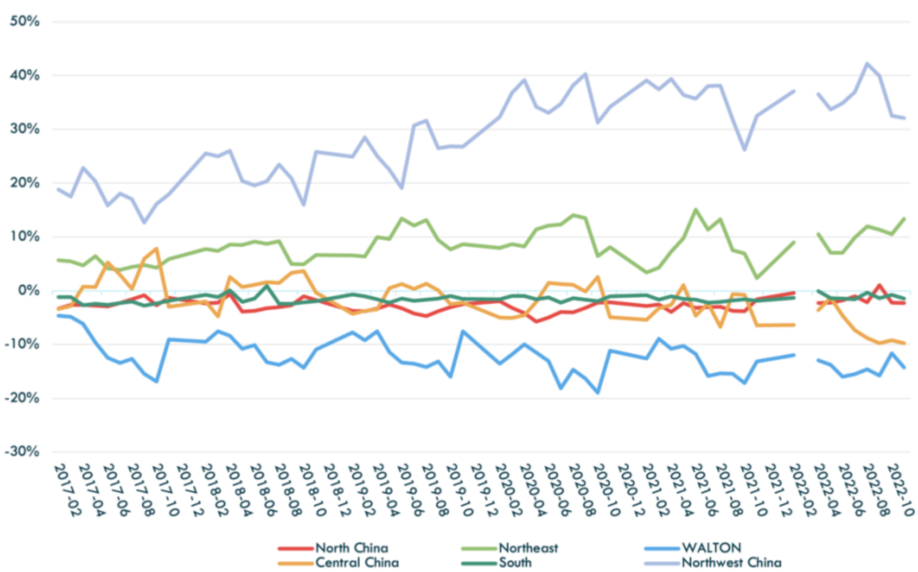
4 Inflexible Power Pricing and Transmission Drive New Coal Investments

4.1 China rocked by a series of supply crises over 2021-2022

Whilst transmission constraints threaten to limit the pace of renewables integration, they also partially explain the recent jump in the development of new coal capacity. The previous section clearly shows that the justifications for new coal capacity rest on shaky grounds, but the growth and volatility expected in China's seasonal peak loads, coupled with the inability of many provinces to transact large volumes of power at short notice, creates incentives to invest in proximate coal capacity. However, each marginal coal capacity addition places further downward pressure on average utilisation rates, incrementally worsening the financials of the fleet as a whole. New coal investments at the scale planned therefore represent a costly way to manage growing peak loads, given that these coal plants must be retired early or increasingly sit idle to avoid compromising China's stated emissions targets.

Although China's power sector suffers overcapacity at the national level, these assets and resources are not evenly geographically distributed. As can be seen from the chart below, the North-eastern and North-western grid regions regularly operate with significant surplus generation relative to peak consumption, with other grid regions operating at minor deficits (aside from Eastern China, which consistently faces material shortfalls). Whilst China is in the process of setting up and trailing interregional spot markets to facilitate more short-term power trading, most cross-regional trading is still determined on the basis of mid to long-term, pre-agreed quotas. So long as these mismatches between regional supply and demand are relatively stable, the mid- to long-term trading contracts were sufficient to maintain security of supply, although renewables curtailment was a major concern (more below). However, the inflexibility of these trading arrangements creates a frailty in China's power system, meaning that it struggles to cope with large or unexpected increases in peaks loads. The experiences of many provinces in late 2021 and 2022 represent a case in point for the challenges faced by the Chinese power sector in balancing the need to decarbonise with the need to meet growing power demand and ensure system stability.

FIGURE 10: CHINA'S REGIONAL GRIDS' MONTHLY PEAK GENERATION RELATIVE TO PEAK CONSUMPTION



Source: Wind Financial Terminal
Note: Data during the supply crisis around 03/2022 is not publicly available

Beginning in 2021, sharp and sustained increases in domestic coal prices, coupled with an inflexible power pricing mechanism, left many coal generators unwilling to operate; this period of high elevated prices was followed by a series of extreme heatwaves contributing to spikes in peak loads from air-conditioning demand, particularly in the Eastern, Southern and Central grid regions. According to the Centre for Research on Energy and Clean Air, the highest recorded momentary load increased by 230GW in 2022[xxvii]. Together, these increases in peak consumption against a backdrop of stable or even declining generation precipitated a series of nationwide supply crunches, with many provinces suffering rolling blackouts[xxviii].

Whilst any power system would struggle to adapt to these shocks, the situation in China was made worse by rules governing how power is regionally transmitted. Trading via longer-term quotas priced at fixed rates introduces a rigidity that means the system is unable to respond swiftly to short-term supply and demand dynamics between the sources of generation and consumption; moreover, this inflexibility becomes increasingly apparent during periods of unexpected tightness and, in 2022, this tightness was arguably most severe in Sichuan province. Sichuan's power system is dominated by hydropower (>70% of installed capacity) which is relied upon to satisfy over 80% provincial demand in what are typically the rainy months of the summer[xxix]. In 2022, the combination of below average rainfall and unexpected increases in power demand due to severe heatwave meant that the province's power system was unable to satisfy local consumption, with Sichuan's peak load at one point increasing by over 25% YoY to reach 65GW[xxx]. Making matters worse, during this period, Sichuan was nevertheless expected to satisfy its long-term contracted export quotas to other neighbouring provinces[xxxi]. In response, local dispatchable power sources were requested to run at near full capacity and energy-intensive industrial consumers asked to curb demand. Although the situation has generally improved, some nearby provinces are still experiencing supply issues, with Yunnan province imposing consumption curbs in early 2023[xxxii].

Whilst Sichuan was arguably worst affected by the crisis, the events speak to wider issues faced across the country. Almost across the board, the response to the supply crisis has been a jump in coal investments, which are now at a pace unseen since 2015-2016. The recent increase in coal investments appears mainly motivated by the security of supply concerns and a desire to avoid a recurrence of the events of 2021-2022, with provinces eager to ensure that local generation can be surplus to future jumps in peak loads. Regulatory reforms to grid management and power pricing could instead facilitate greater use of existing transmission infrastructure and generation capacity, unlocking some latent potential in China's grid and removing many of the motivations for more local coal capacity.

4.2 China's progress in power market reform

Since the early 2000s, Chinese regulators have been attempting to introduce more efficiency into the power system by reforming power pricing mechanisms. Power tariffs were historically administratively determined at the provincial level, with coal plants allotted guaranteed hours and receiving compensation based on estimated levelized costs. These benchmark tariffs were supposed to be periodically adjusted to reflect changes in fuel prices but, in reality, adjustments were rare, occurring just 12 times between 2004-2015[xxxiii]. This meant that prices seldom reflected changes in the marginal costs of generation[xxxiv]. In 2015, a suite of reforms sought to introduce better pricing signals, including via the introduction of bilateral negotiations between large power consumers and generators, however the extent of marketisation is not uniform between provinces and a significant proportion of generation is still priced at fixed benchmarks. Regional differences in coal prices also meant that these benchmarks differed markedly between provinces.

Following the 2021 increases in coal prices, tariff ranges were allowed to deviate +/-20% from the fixed provincial benchmark tariffs, and all industrial consumers were instructed to begin procuring power in competitive wholesale markets, which is further progress towards introducing greater price discovery into the system. However, as of 2022, 60% of national power generation is market-based and, of these transactions, 80% are mid- to long-term trades[xxxv]. In addition, the floating tariff bands can still differ significantly between neighbouring provinces, which often disincentivises the import of power from nearby provinces with higher prices, in turn encouraging the construction of more local capacity. Overall, just 20% of total power traded in power markets was interprovincial[xxxvi].

China has also sought to introduce greater market pricing into the renewables segment of the power sector by reigning in administrative measures. Historically, wind and solar projects were subsidised and compensated via provincial feed-in tariffs or long-term contracts priced at or below provincial coal benchmark tariffs[xxxvii]. This system was in place during a period of significant renewables curtailment in the late 2010s, exacerbated by the regulatory advantage coal power enjoyed in terms of priority dispatch and guaranteed hours. Reforms such as mandatory renewable consumption quotas, priority dispatch for renewables and payments to coal plants to ramp down during high renewable generation have largely addressed these problems, demonstrating the achievements of power sector reform to date. Following the removal of subsidies for wind and solar projects in 2021, pilot green power markets were launched based on mid- to long-term trading arrangements, opening up additional revenue channels for renewable developers outside of feed-in tariffs[xxxviii]. Independent purchasers of power in these markets also receive 'Green Energy Certificates' (GECs), which can then be bought by entities unable to participate in the pilot markets for use in satisfying renewable consumption quotas[xxxix].

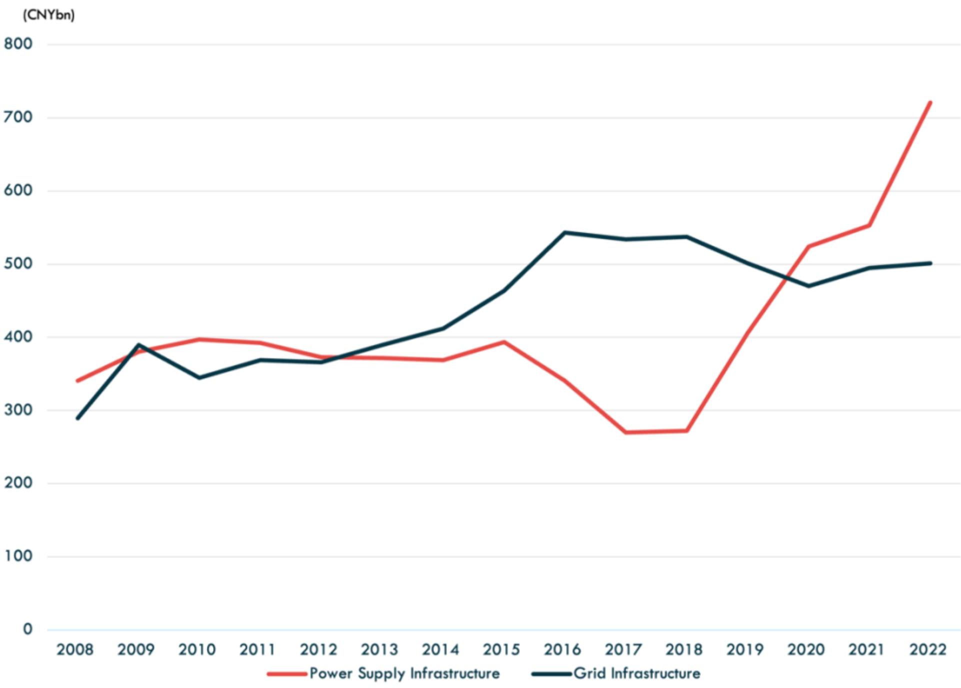
Although this incentivises large energy consumers to procure green power directly from generators, the long-term nature of marketized green trading still places renewables at a disadvantage relative to coal, given that the variable nature of the power means project developers cannot predict generation far in advance. To improve shorter-term pricing signals which could benefit renewables, China has also established 14 intra-provincial spot power markets, five of which have progressed past initial trial stages, but each differs slightly in design[xl]. Amongst broader efforts to create a 'Nationally Unified Power Market'[xli], in July 2022, the first inter-provincial power market began trial operations in China's Southern region, which (amongst other things) expanded spot trading from an active intra-provincial market in Guangdong to four other provinces[xlii]. These interprovincial spot markets could provide a more efficient forum for buyers and sellers of power to iron out temporary dislocations in regional supply and demand, which will become especially important as variable generation increases. China has now released two documents for public solicitation which outline provisional uniform rules for constructing cross-provincial spot markets[xliii]. But the preference for mid-to-long term contracts means that spot trading currently accounts for only 20% of total marketized trading, with renewable power occupying just a fraction of this share[xliv].

Despite intending to promote the consumption of renewable power, prices realised in existing spot markets have occasionally created disincentives for renewables to participate. For example, in the first five months of 2022, spot prices in Shanxi province often dropped the provincial benchmark coal tariff when plants sold power below their operating costs, leaning on longer term markets for the majority of their revenues. The low marginal costs of renewables means that they are rarely price setters in spot markets with economic dispatch and, as a result, wind and solar farms in the province had to sell power at discounts of up to 63% relative to the benchmark tariff[xlv]. Hence, experiments in short-term markets are still heavily influenced by the legacy benchmarking system. Moreover, in late 2022, the National Energy Administration and the National Reform and Development Commission reaffirmed the centrality of long-term contracts in industrial energy consumption and interregional transmission, stating that 90% of these transactions should be contracted on this basis[xlvi]. Despite the encouraging signals from regulators on introducing better short term price discovery, the desire for price stability is still taking precedence over the introduction of efficient price signals which could incentivise more renewables consumption and flexible interprovincial trading. The pace at which provincial governments will seek to construct or unify their spot markets is therefore unclear, and the jump in coal investments demonstrates that the preference to construct nearby coal capacity is still deeply entrenched.

4.3 Existing transmission infrastructure often remains underutilised

Regulatory barriers aside, China's sheer size and the disparity in regional generation also means that the power system faces significant engineering and technological challenges when it comes to increasing the long-distance transfers needed to modernise the power system. China has been investing heavily in transmission infrastructure, including ultra-high voltage (UHV) transmission lines specifically designed for transmitting variable renewables, with the goal of reducing constraints between surplus regions in Northern and Western China and demand centres in the Southeast. This infrastructure is critical for complementing power sector reform, resolving the regional imbalances and constructing a power system based on clean energy. However, despite outlining ambitious transmission capacity targets in the 13th and 14th FYP, the proclivity of provincial governments has tended to be on investment in generation capacity, with supply side investments growing rapidly since 2017 and surpassing completed grid infrastructure investments in 2020[xlvii].

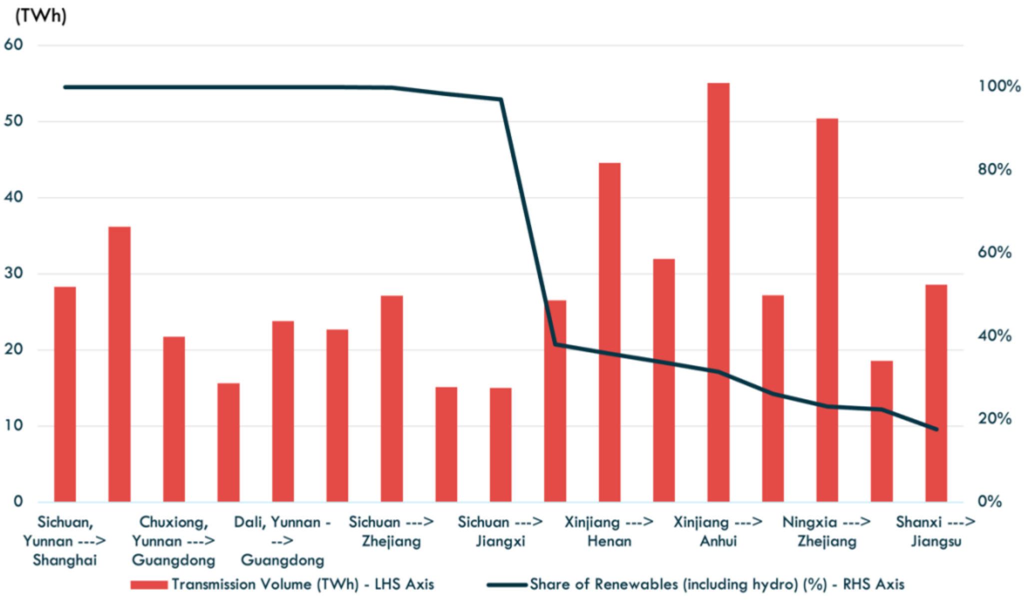
FIGURE 11: COMPLETED INVESTMENTS IN GRID INFRASTRUCTURE VS POWER SUPPLY INFRASTRUCTURE



Source: Wind Financial Terminal

The long-distance nature of the power lines means that they are complex projects crossing the remits of multiple regional grid companies. Debates over how these investments are shared have meant that capital deployment in grid infrastructure has often been relatively uncoordinated, failing to keep up with the pace of supply side investments. It should be noted that much of the increase in supply side investment is due to the rollouts of wind and solar. However, the point remains that, in spite of ongoing grid investments, the lack of coordination with supply has meant that while some transmission lines operate at high capacity, others remain underutilised. At the national level, reports have stated that China's UHV lines were running at just 60% of planned capacity in 2020[xlviii], hampered by the lack of storage or dispatchable support to stabilise variable renewable output. Of the power that is transmitted via these lines, there is also significant differences in the extent to which it is generated using low carbon sources. As can be seen from the chart below, the transmission volumes of many older lines originating in the hydro-rich regions of Sichuan and Yunnan transporting power to the Eastern load centres are comprised of 100% low-carbon power (i.e. renewables and hydro), whereas this proportion for newer lines in Inner Mongolia and Xinjiang is significantly lower (20%-40%)[xlix].

FIGURE 12: CHINA'S OPERATING UHVDC TRANSMISSION LINES -2022 DATA



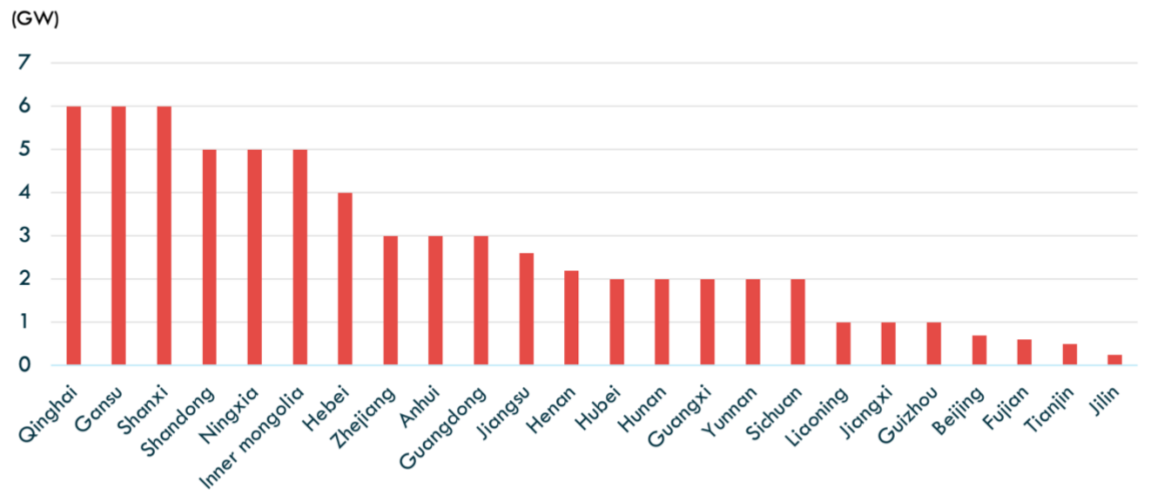
Source: S&P Global

In a report dated March 2021, State Grid via State-Owned Assets Supervision and Administration Commission stated that it planned to increase the nationwide share of low-carbon power transmitted via cross-regional UHV transmission lines to over 50% by the end of the 14th FYP, representing an increase of 7% compared to the 13th FYP [l&li&lii]. These targets are expressed within State Grid's 'Carbon Peaking and Neutrality" plan, which also seeks to increase UHV transmission capacity by 56GW via 7 new installations by 2025[liii], from a base of164GW in 2020[liv]. The increased transmission capacity from the renewable energy bases in Northern China will facilitate the transmission of more renewable power to where it's needed in the South, however there are technological reasons why many lines from the North have historically channelled relatively low levels of renewables. The variable nature of renewable generation often means that it must be packaged together with dispatchable sources[lv] (explaining the high transmission volumes of coal and hydro), as sudden drops in renewable output can compromise grid stability.

4.4 Insufficient Economic Incentives exist for Storage Utilisation

This means that many provinces at both the origin and destination of long-distance transmission lines are often required to construct new coal capacity with the expressed intention of 'supporting' grid stability by compensating for the periodic drops in renewable output[lvi]. As discussed in the previous section, declines in the cost of batteries mean that China is approaching the point at which coupling renewables with onsite storage could replace the balancing role currently assumed by coal without net financial losses. Alongside requirements for coal to stabilise new renewable capacity, at the beginning of the 14th FYP, 7 provinces (including Inner Mongolia, Shandong and Qinghai) announced requirements for developers of renewables projects to install on-site storage; as of 2022, at least 20 provinces had published targets for new energy storage capacity additions by 2025, including targets for 6GW in Gansu, Qinghai and Shanxi[lvii]. Cost competitiveness on a levelized basis indicates that provinces are on strong footing to achieve these targets, however data indicates that existing market structures do not fully support the business case for renewables plus onsite storage.

FIGURE 13: 14TH FYP NEW ENERGY STORAGE CAPACITY ADDITIONS (GW)



Source: International Energy Net (in-en.com)

A report released by China Electricity Council in 2022 indicates that, whilst provincial governments are ahead of schedule in terms of deploying storage capacity, utilisation rates are low. At the end of 2021, national average utilisation[lviii] of renewables plus storage was as low as 6% (although utilisation rates in the Northern-eastern and North-western renewable bases were highest)[lix]. The underutilisation is likely explained by the lack of appropriate channels for compensating developers for the system value of the technology. Most wind and solar farms can take advantage of feed-in tariffs, but the project economics of storage capacity is typically dependent on variability in power prices. This is due to arbitrage opportunities where storage providers can buy low-priced power during surplus supply, before selling back into the market at higher prices during supply tightness. As discussed above, most power in China is transacted and dispatched via quotas with fixed prices, meaning that market opportunities for storage developers are insufficient. Provinces have implemented time-of-use retail tariffs where a spread exists between peak and off-peak retail prices[lx], but these mainly incentivise demand response and demand-side storage. In some provinces, such as Qinghai, subsidy schemes exist for renewable plus onsite storage, with the subsidy set at 0.1/kWh, which help to cover some fixed costs[lxi]. However, in the absence of wider subsidy support or mature out-of-market revenue channels, mandates for renewables plus storage risk burdening project developers with additional investment costs which they are unable to recover.

Consistent messaging from the central leadership confirming the intention to promote marketisation indicate that these are a top priority in ongoing reforms. This said, reforming a power system as disparate as China's will be a protracted, complex process. Similarly, constructing cross-regional transmission infrastructure needed to transport renewable power is a highly capital-intensive, technically challenging and long-term engineering project. These challenges do not change the fact that many (if not all) of the recently announced coal investments will either face low utilisation rates or early closure. Whilst the larger nationwide infrastructure projects and reforms progress, focus should be more on incremental improvements, such as enforcing of commitments against new baseload coal, better coordination of existing pilots, improving the dynamics of shorter-distance interprovincial transfers and increasing the marketisation of renewable power trading. Importantly, regulators should recognise that reforming the power sector to accommodate more low-carbon power must entail less control over prices, and that regular administrative interventions impede the pricing signals that are necessary for consistent progress in decarbonising the grid.

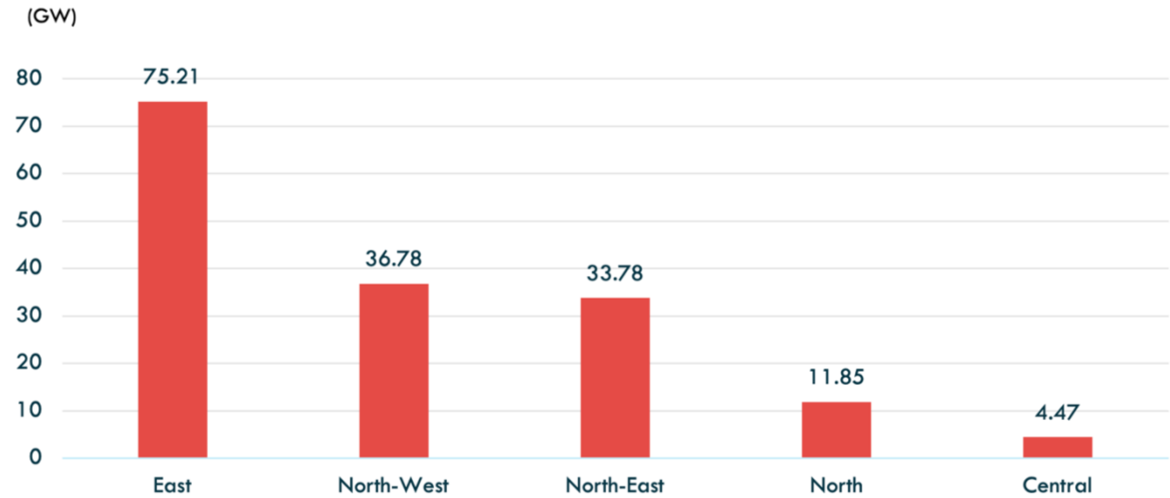
5 Supply-Side Flexibility Crucial for Emissions Reductions

Aside from flexibility in pricing and transmission, another key factor in the pace of China's power sector decarbonisation is flexibility on the supply side to ensure that growing renewable capacity is maximally utilised. Seasonal fluctuations and uneven geographical distribution of hydro resources means that, even assuming sufficient transmission capacity, these resources cannot always be relied upon to help accommodate renewable power. In many countries, flexible generation is provided by gas-power, which can quickly ramp up and down to help manage fluctuations in supply and demand. But with little installed gas capacity and a reluctance to grow reliance on increasingly volatile global gas markets, China is currently left with coal power as its main source of flexible generation, especially in light of the market barriers facing storage providers. Although China's operating coal fleet is relatively young by international standards, most coal plants were designed to provide baseload generation, meaning that these assets generally have long start-up times, slow ramping rates and the inability to operate stably at low loads.

As discussed in the previous section, preferential dispatch for coal power and the technical difficulties of adjusting coal generation over short periods of time contributed to severe curtailment of renewables during the 13th FYP period. Reforms to dispatching arrangements have significantly reduced this issue, however recognising the need for greater supply side flexibility, China also began a program of technological retrofitting to improve the regulative ability of its operating coal units. Beginning in 2016, the National Energy Agency and the National Development and Reform Commission initiated two pilot programs to enhance the flexibility of 45 coal units with a combined capacity of 17GW, located mainly in the North-eastern grid region[lxii&lxiii]. This program has three purposes: enable 'deep load cycling' by lowering the minimum load at which the plants can safely operate; improve flexible 'peak shaving' operations by increasing ramping rates; and the decoupling of heat-and-power generation for CHP plants to increase the peaking capacity from c.20% to 40% of nameplate capacity[lxiv]. In particular, the decoupling of heat-power production for CHP units is critical given the concentration of these units in the northern regions with high levels of renewables. This is because these CHP units must run at high capacity to provide district heating in the winter months, reducing the flexibility of power generation during this period[lxv].

Combined with longer-term transmission upgrades and power sector reforms, these retrofits could enable swatches of the operating fleet to begin to assuming a more flexible role, reducing aggregate emissions and increasing the pace at which renewable power can be fully utilised. China is not the first country to have retrofitted its legacy coal units as a means of providing flexibility, with Germany having previously implemented similar programs to ease the integration of renewables[lxvi]. Alongside the two pilots mentioned above, according to public reports from Chinese brokers[lxvii], after the initiation of these pilots a further of 162GW of capacity was retrofitted during the 13th FYP period, with a nationwide retrofit target of 200GW by the end of the 14th FYP period[lxviii&lxix].

Figure 14: 13th FYP retrofitted capacity by grid region



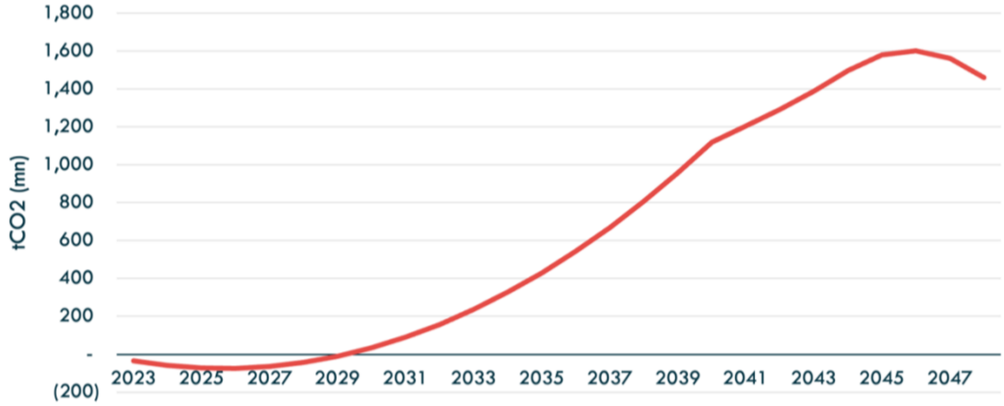
Source: State Grid via Topsperity Securities

Some provinces (such as Inner Mongolia) have also publicly released lists of specific coal-units which have completed or are undergoing retrofitting[lxx]; the provinces of Xinjiang, Henan and Hubei have published retrofit capacity quotas totalling 21GW, whereas the north-western grid region as a whole is targeting a retrofit capacity budget of 40GW[lxxi]. Using these publicly available sources, we collectively identified the regional location of retrofitted capacity totalling 130GW; using the residual regional capacities identified from broker reports, we selected a further 70GW of operating capacity suitable for retrofitting by assumption using characteristics from the known sample set, regional quotas from broker reports and selection criteria publicly published by the National Development & Reform Commission[lxxii].

On the assumption that these retrofits are successfully completed before the end of the 14th FYP, we expect that this program will have significant financial and environmental implications. Firstly, technological retrofits are capital-intensive projects and, although these can differ materially based on retrofit type and unit specifications, industry experts believe the costs to be between CNY 500-1500/kW[lxxiii]. Secondly, if retrofitted units begin to assume a more flexible role as intended, the more frequent ramping and operation at lower loads will increase fuel consumption per unit of power generated, decreasing their operational efficiency and increasing the assets' depreciation[lxxiv]. Thirdly, the assumption of more flexible roles means that these units' average annual capacity factors will likely decrease at a more rapid rate relative to the rest of the fleet (which already face significant downward pressure on utilisation rates); a 2022 report from Peking University suggested that capacity factors for flexible coal units could drop by as much as 50%[lxxv]. Finally, whilst lower total generation translates into fewer aggregate lifetime emissions, this also creates an opportunity cost from foregone wholesale power sales.

With these new retrofitting assumptions feeding into our model, we ran a scenario analysis to give an approximate indication of the scale of emissions reductions that could be achieved through the program. If formerly baseload coal units begin seeing more rapid declines in utilisation rates[lxxvi] as they assume a more flexible role, cumulative emissions from these units could be lowered by over 1.4bn tCO_2 by 2050 relative to a counterfactual scenario in which these plants remain as baseload. These emissions reductions are driven by the expectation that, despite the decrease in operational efficiency, faster declines in utilisation rates outweigh these impacts, cumulatively lowering aggregate coal consumption and CO_2 emissions.

FIGURE 15: POTENTIAL CUMULATIVE TCO2 EMISSIONS AVOIDED VIA RETROFITTING PROGRAM

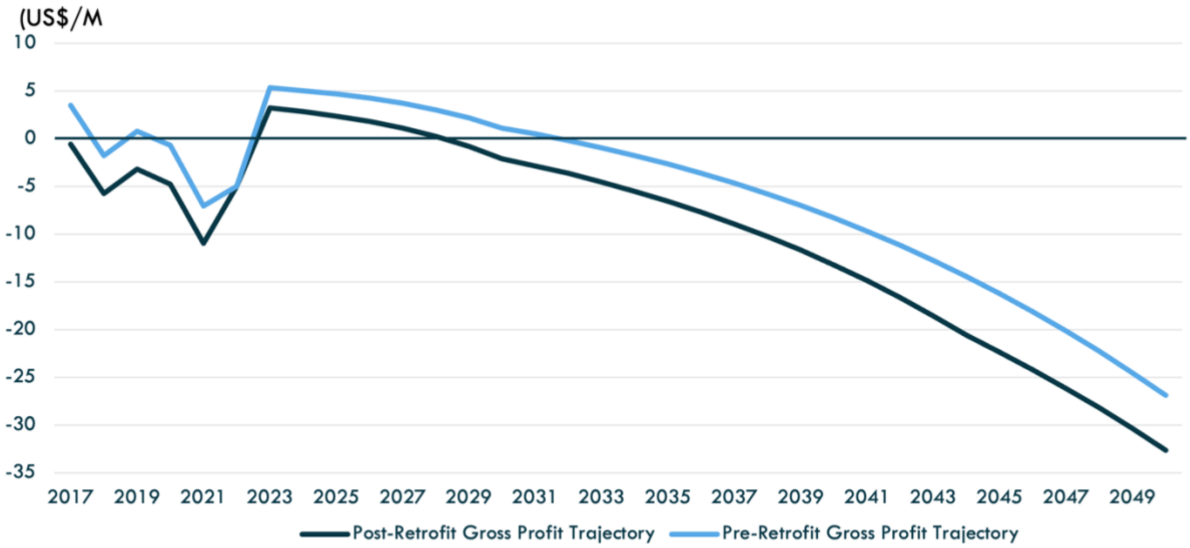


Source: Carbon Tracker Data

Importantly, the system value of these units is improved as they will be able respond better to surges in renewable generation by ramping down, reducing the risk of future renewables curtailment, as well as ramping up to stabilise the grid in response to short term increases in demand. For instance, for the 40GW of retrofitted capacity in the North-western grid region, the peaking capacity of these units is expected to be increased by 50GW, which could in turn facilitate the integration of an additional 55TWh of renewable generation per year (1.8% increase)[lxxvii]. Improving the flexibility of the operating fleet could therefore mean that less aggregate coal capacity needs to be added to manage peak loads, largely stripping away remaining justifications cited for building new capacity in terms of system stability.

But these improvements in flexibility come at a cost. As discussed in the previous section, under current market structures in China, most power is transacted in mid to long-term wholesale markets. This creates a financial incentive for coal plant operators to maximise baseload generation, increasing the volume of power available for sale in fixed quotas. According to our analysis, the gross profitability (based on wholesale market revenues) of retrofitted units is materially worsened, explained mainly by the capital costs incurred during retrofitting and increased coal costs per MWh of flexible generation. Considering these costs, expanding out-of-market revenue channels to help make up for this lost value will be necessary to ensure that transitioning to flexible operations is an economically attractive alternative to baseload, increasing the potential for the retrofitting program to maximise future emissions reductions.

FIGURE 16: GROSS PROFIT TRAJECTORY OF RETROFITTED VS UNRETROFITTED COAL UNITS BASED ON WHOLESALE MARKET REVENUES

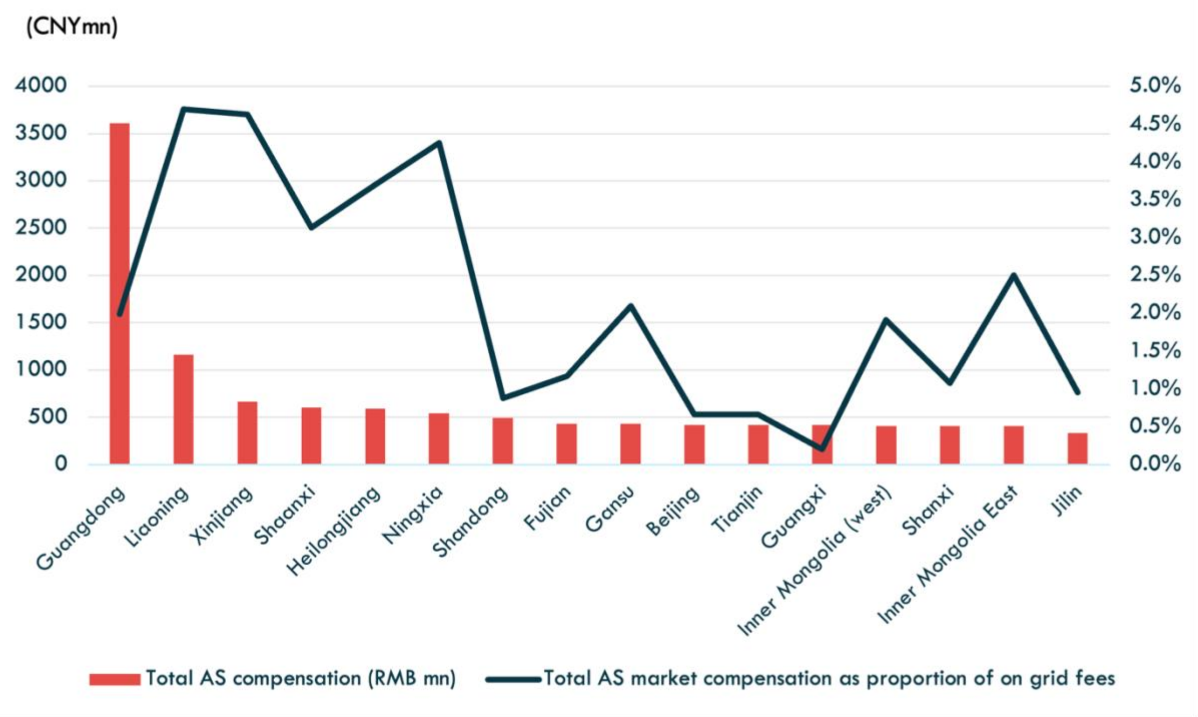


Source: Carbon Tracker Data

Ancillary service and capacity markets offer a route to help cover this shortfall. In the case of ancillary service (AS) markets, flexible generators are compensated for the costs incurred by (amongst other things) regulating their generation to stabilise the grid and accommodate variable renewable power. In China, multiple subsidy schemes were implemented to compensate coal generators for downward ramping (or 'peak shaving'). The size of the subsidy payments depends on the extent to which the units can feasibly ramp down, with higher payments made to units able to reach lower loads. These subsidies have been successful in reducing curtailment, however the nature of a subsidy program means that the flexibility was not necessarily provided by the most efficient generators on market-based terms. China has since refined its AS markets, which now cover all six grid regions, with generators bidding prices at which they would be willing to ramp down below nameplate capacity.

In late 2021, the National Energy Administration published a draft document outlining the general principles which will underpin the expansion of AS markets at the national level. This document included plans to raise the profile of other compensated services, such as frequency modulation, as well as to plans to ensure that the costs of providing ancillary services are passed through to end consumers[lxxviii]. The eligibility to participate in AS markets was also expanded to battery storage providers, which will improve their revenue opportunities and ability to compete with coal as flexibility providers in the system. This was followed by reports that in 2022, total revenues earned in China's AS markets reached CNY32bn (c.US$ 4.7bn), up roughly 20% from 2019 levels[lxxix]. Approximately 95% of total AS revenues are paid out to thermal generators[lxxx], indicating that whilst the incentives for coal plants to provide grid-stabilising services as opposed to baseload have deepened, these revenues are still very low as a proportion of total on-grid fees at 1.5%[lxxxi].

FIGURE 17: 1H2019 AS MARKET REVENUES (TOP 16 PROVINCES)



Source: NEA data via Tebon Securities

Capacity markets are prevalent in many mature power markets and provide payments to help cover fixed costs of keeping power plants in serviceable conditions to ramp up and meet future power demand. Currently, although some provinces have implemented administratively set capacity payments as part of spot market pilots, notably in Shandong[lxxxii], we are unaware of any fully functioning Chinese capacity markets. However, reports from 2022 show that plans are underway to establish these schemes. In particular, capacity mechanisms are being explored as a means for compensating new coal projects mandated in the northern regions to support planned renewable projects[lxxxiii]. Though these plans are still being drawn up, including planned coal capacity in the eligibility for future capacity markets would increase the incentives for project developers to proceed with the investments, raising the likelihood that much of the pipeline goes ahead. Given that the non-financial justifications for these supporting coal plants is reduced if reforms to transmission and power trading are successful, the scope of any future capacity markets should only be explored insofar as they would provide financial incentives for the most flexible and efficient operating coal units to reduce utilisation rates and invest in flexibility. Moreover, the extension of capacity payments to coal generators should be determined on market-based terms, such as via competitive auctions, to avoid distortive effects of administrative price setting and ensure that payments are efficiently allocated.

The emissions reductions and improved flexibility that can be achieved through the retrofitting program warrants its expansion to all coal plants for which it is technically feasible. Currently, China has been implementing this program on the basis that any units which can be retrofitted, should be retrofitted. According to the sample set of retrofitted units that we have attained via public sources, the vast majority are 300MW-600MW sub and super-critical units. This said, public interviews with senior engineers in mainland China[lxxxiv] describe how larger, 1000MW+ ultra-supercritical units have also been successfully modified for flexibility, highlighting the potential for more widespread transformations. However, these experts also explain that, especially in light of sustained elevated coal prices, the financial incentives to implement these technologies are not always sufficient, whereas the incentives to provide baseload are clear. Expedited development of AS and capacity markets for operating units could help provide these incentives, but the rate at which emissions will be reduced partly depends on the pace at which these out-of-market revenue schemes are expanded. If successful, greater incentives for flexibility in ongoing reforms could pave the way for much future peaking capacity to be met by existing coal units, meaning that significant portions of the planned pipeline could be mothballed or cancelled, averting locked-in emissions and reducing financial losses. Careful coordination with other reforms, such as the expansion of spot markets and green power pilots, is important to ensure that incumbent generators do not use multiple markets to earn double compensation for providing the same flexibility services.

6 Key Conclusions

- **China's planned investments of over 200GW of new coal capacity could lead to between US$26bn-US$40bn of value destruction via asset stranding.** These coal plants will join a fleet already suffering financial stress and long-term declines in utilisation rates; returning to profitability under current market structures would require significant increase in power prices to pass high commodity and carbon costs through into the real economy.

- **Planned coal capacity not critical for managing peak loads or providing district heating should be mothballed or cancelled to reduce stranded assets and environmental risks.** Previously stated commitments to prevent the construction of additional baseload coal capacity should be more stringently enforced.

- **Renewables now outcompete coal on economic grounds in almost every Chinese grid region. China has led the world in the deployment of wind and solar energy, bolstered by the strong economic case for renewables over coal.** Levelized costs of solar photovoltaics and wind have fallen below the levelized costs of new coal power. This means that funds designated for planned coal investments could be diverted into renewables investments without financial losses.

- **Reforms for grid management could increase utilisation of existing transmission infrastructure while longer-distance transmission infrastructure is built.** Transporting power from the source of generation to the source of consumption is beset by bottlenecks. Better planning and coordination between transmission and supply side investments should be prioritised as more transmission capacity is built out. Incremental reforms to quota-based interprovincial trading could improve utilisation of existing transmission capacity.

- **Regulators should recognise that reforming the power sector to accommodate more low-carbon power must entail less administrative control over prices.** The expansion of marketisation should continue, encouraging more price discipline and the increased integration renewables. Recent relaxation of the benchmarking approach to power pricing are welcome developments. However, there is still room for increasing the share of power traded in competitive markets, particularly for renewables, and regular administrative interventions impede stronger pricing signals necessary for a more flexible, low-carbon grid.

- **Technological retrofitting of coal units to enable greater flexibility could have significant positive implications for emissions reductions and system stability.** The potential emissions reductions warrant the expansion of the program to all units for which it is technically feasible. However, it is unclear that sufficient economic incentives always exist for coal plants to transition from baseload to flexible generation.

- **Out-of-market revenues from ancillary service markets could help provide financial incentives for greater flexibility and utilisation of storage.** Ancillary service revenues will be an important part of creating revenues streams which incentivise investment in supply-side flexibility. Expanding the breadth of compensated services in these markets will be critical for shortening the timeframe for low-carbon technologies, such as storage, to replace coal's role in grid balancing.

- **Capacity markets could help existing coal units cover fixed costs whilst lowering generation and emissions.** These markets should be explored for operating coal capacity to incentivise in utilisation rates, expediting the phaseout of baseload coal generation. Importantly, these payments should not be used as an excuse to build new coal or keep inflexible capacity online. Payments should be determined via competitive auction to avoid distortions from administrative price setting.

- **Better coordination of reforms will be needed to avoid unintended consequences of marketisation.** A continuation of China's piecemeal approach to reforms could create opportunities for incumbent coal generators to exploit their market power to the disadvantage of renewables. Better integration of segregated markets, particularly at the regional level, will be important for ensuring that these reforms are effective in benefiting renewables.

7 Appendix

Regional Renewable LCOEs by Technology Type and Coal LCOE

East	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Solar PV	24	22	21	20	19	18	18	17	17	16	16	15	15	14	14	14	13	13
Solar PV + Storage	56	52	49	47	44	42	41	40	38	36	36	34	34	33	33	31	31	30
Onshore Wind	24	22	21	19	19	18	18	17	16	16	15	15	15	14	14	13	13	13
Onshore Wind + Storage	47	43	41	39	37	35	34	33	32	30	30	28	28	28	27	26	26	25
Offshore Wind	64	59	55	52	50	48	47	45	44	43	41	40	39	38	37	36	35	34
Coal LCOE	79	79	79															
South	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Solar PV	25	23	21	20	19	19	18	17	17	17	16	15	15	15	14	14	13	13
Solar PV + Storage	58	53	50	47	45	43	41	41	39	37	36	35	34	34	33	32	31	31
Onshore Wind	38	35	33	31	30	29	28	27	26	26	25	24	23	23	22	22	21	20
Onshore Wind + Storage	75	69	65	62	59	56	54	53	51	49	48	45	45	44	44	42	41	40
Offshore Wind	64	59	55	52	50	48	47	45	44	43	41	40	39	38	37	36	35	34
Coal LCOE	80	81	81															
North	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Solar PV	22	20	19	18	17	17	16	16	15	15	14	14	13	13	13	12	12	12
Solar PV + Storage	52	47	45	42	41	39	37	36	35	33	33	31	31	30	30	28	28	28
Onshore Wind	29	27	25	24	23	22	21	21	20	20	19	18	18	17	17	16	16	15
Onshore Wind + Storage	57	53	50	47	45	43	41	40	39	37	36	35	34	34	33	32	31	31
Offshore Wind	64	59	55	52	50	48	47	45	44	43	41	40	39	38	37	36	35	34
Coal LCOE	71	72	72															
North-West	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Solar PV	21	20	18	17	17	16	16	15	15	14	14	13	13	13	12	12	12	11
Solar PV + Storage	49	45	43	41	39	37	36	35	33	32	31	30	29	29	29	27	27	27
Onshore Wind	53	49	46	43	42	40	39	38	37	36	34	33	33	32	31	30	29	28
Onshore Wind + Storage	105	96	91	86	82	79	76	74	71	68	66	63	62	62	61	58	57	56
Coal LCOE	67	67	67															
North-East	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Solar PV	22	20	19	18	17	16	16	15	15	15	14	14	13	13	13	12	12	12
Solar PV + Storage	51	47	44	42	40	38	36	36	34	33	32	30	30	30	29	28	28	27
Onshore Wind	20	18	17	16	15	15	14	14	13	13	13	12	12	12	11	11	11	10
Onshore Wind + Storage	38	35	33	32	30	29	28	27	26	25	24	23	23	23	22	21	21	21
Coal LCOE	62	62	62															
Central	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Solar PV	25	23	22	21	20	19	19	18	17	17	16	16	15	15	15	14	14	13
Solar PV + Storage	59	54	51	49	46	44	42	42	40	38	37	36	35	35	34	33	32	32
Onshore Wind	42	38	36	34	33	31	31	29	29	28	27	26	25	25	24	23	23	22
Onshore Wind + Storage	82	75	71	67	64	61	59	58	55	53	52	50	49	48	48	45	45	44
Coal LCOE	85	84	84															

Red indicates renewable technology is more expensive than the LCOE of coal in the given region; green indicates the LCOE is cheaper than coal. Units: (US$/MWh)

[i] https://energyandcleanair.org/wp/wp-content/uploads/2023/02/CREA_GEM_China-permits-two-new-coal-power-plants-per-week-in-2022.pdf
[ii] https://iea.blob.core.windows.net/assets/b0beda65-8a1d-46ae-87a2-f95947ec2714/WorldEnergyInvestment2022.pdf
[iii] https://energyandcleanair.org/wp/wp-content/uploads/2023/02/CREA_GEM_China-permits-two-new-coal-power-plants-per-week-in-2022.pdf
[iv] https://energyandcleanair.org/wp/wp-content/uploads/2023/02/CREA_GEM_China-permits-two-new-coal-power-plants-per-week-in-2022.pdf
[v] https://globalenergymonitor.org/projects/global-coal-plant-tracker/
[vi] Net present value is the difference between the discounted expected cash inflows and outflows of a project, and is used to analyse the predicted profitability of an investment.
[vii]The CTI net-zero by 2050 scenario is a regional interpolation of the IEA's global NZE2050 scenario and the regional Sustainable Development Scenario (SDS). The IEA's NZE2050 scenario models a global phaseout of unabated coal generation that is consistent with approximately 1.5 degrees Celsius of global average temperature increases relative to pre-industrial levels. To estimate how China's coal generation would decline under IEA NZE2050, we take China's proportion of the global coal phaseout in IEA's SDS scenario (which contains regional breakdowns), and scale this to the global pathway in IEA NZE2050. For more information, please see this methodology document: https://carbontracker.org/wp-content/up-loads/2022/04/PDG-Asia-Methodology_Final.pdf
[viii] See this link for more details on the China Tsinghua 2060 phaseout scenario: http://www.csee.org.cn/pic/u/cms/www/202102/0215054225qp.pdf.
[ix] See this link for more details on the China Tsinghua 2060 phaseout scenario: http://www.csee.org.cn/pic/u/cms/www/202102/0215054225qp.pdf.
[x] Stranded asset balances represent the difference in an asset's profits over its natural operating life relative to a shortened operating lifetime if retired prematurely under a climate scenario. We calculate the stranded asset risk incurred by the planned coal units in each climate scenario as the difference between the discounted net profits in the business as usual (BAU) scenario and the climate constrained scenario.
We calculate the stranded asset risk incurred in each climate scenario as the difference between the discounted operating profits in the business as usual (BAU) scenario and the climate constrained scenario.
[xi] Our provincial coal price assumptions are sourced using the Wind Financial Terminal and are based on an 80/20 split between purchases via long-term contracts versus spot markets. Recently, domestic coal supply has been tight, meaning that longer-term contracts (which are typically cheaper than spot purchases) are more difficult to procure. As such, our 80/20 split in the coal price assumptions may slightly underestimate the actual fuel costs incurred by coal plants.
[xii] https://energyandcleanair.org/wp/wp-content/uploads/2023/02/CREA_GEM_China-permits-two-new-coal-power-plants-per-week-in-2022.pdf
[xiii] For our carbon price assumptions, we rely on Refinitiv's forecasts which see Chinese carbon prices to rise to CNY190 by 2030. Post-2030, we assume that the forecast 2030 carbon price increases at the 2022 rate of inflation. We do not assume that China's ETS transitions to an absolute cap, and assume a linear tightening of the emissions intensity benchmark to 0.5g/kWh by 2060, based on a projection published by Nengyuan Magazine. http://www.inengyuan.com/kuaixun/4185.html
[xiv] We exclude captive CHP plants from our modelling on the assumption that they are owned by and serve a nearby industrial complex, and therefore do not sell power to the grid or provide district heating. In addition, regulators have stated that captive plants will be targeted for early phaseouts.
[xv] https://unearthed.greenpeace.org/2017/03/02/china-coal-plant-approval-fall-2016/
[xvi] https://www.cctd.com.cn/show-19-196018-1.html
[xvii] https://news.bjx.com.cn/html/20211215/1193645.shtml
[xviii] http://zfxxgk.nea.gov.cn/2021-08/27/c_1310486070.htm
[xix] https://energyandcleanair.org/wp/wp-content/uploads/2023/02/CREA_GEM_China-permits-two-new-coal-power-plants-per-week-in-2022.pdf
[xx] Prioritising non-CHP projects which are still in the permitting process for elimination is justified on the basis that abandoning these projects will incur the smallest amount of sunk costs.
[xxi] http://nyj.shandong.gov.cn/art/2022/11/2/art_253733_10294616.html
[xxii] https://www.iea.org/data-and-statistics/data-product/world-energy-investment-2022-datafile
[xxiii] https://energyandcleanair.org/wp/wp-content/uploads/2023/02/CREA_GEM_China-permits-two-new-coal-power-plants-per-week-in-2022.pdf
[xxiv] https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2014/Nov/IRENA_REmap_China_summary_2014_EN.ashx?la=en&hash=807F1019E27CA5C3D36FBA445EC48F150D58A6B5#:~:text=Under%20REmap%202030%2C%20however%2C%20with,about%2020%25%20of%20global%20use
[xxv] https://mp.weixin.qq.com/s/pYG4B112dNnP9zfPs7k9XQ
[xxvi] https://www.carbonbrief.org/analysis-what-do-chinas-gigantic-wind-and-solar-bases-mean-for-its-climate-goals/
[xxvii] https://energyandcleanair.org/wp/wp-content/uploads/2023/02/CREA_GEM_China-permits-two-new-coal-power-plants-per-week-in-2022.pdf
[xxviii] https://www.scmp.com/topics/chinas-power-crisis
[xxix] https://www.lantaugroup.com/file/brief_hydro_aug22.pdf
[xxx] https://www.lantaugroup.com/file/brief_hydro_aug22.pdf
[xxxi] https://energyandcleanair.org/wp/wp-content/uploads/2023/02/CREA_GEM_China-permits-two-new-coal-power-plants-per-week-in-2022.pdf
[xxxii] https://www.inengyuan.com/kuaixun/10496.html
[xxxiii] https://www.e3s-conferences.org/articles/e3sconf/pdf/2021/04/e3sconf_ccgees2021_01013.pdf
[xxxiv] https://www.e3s-conferences.org/articles/e3sconf/pdf/2021/04/e3sconf_ccgees2021_01013.pdf
[xxxv] https://www.oxfordenergy.org/wpcms/wp-content/uploads/2023/02/Assessing-Chinas-power-sector-low-carbon-transition-a-framing-paper-CE4.pdf
[xxxvi] https://www.oxfordenergy.org/wpcms/wp-content/uploads/2023/02/Assessing-Chinas-power-sector-low-carbon-transition-a-framing-paper-CE4.pdf
[xxxvii] https://www.e3s-conferences.org/articles/e3sconf/pdf/2021/04/e3sconf_ccgees2021_01013.pdf
[xxxviii] https://www.cet.energy/2021/09/15/china-energy-policy-newsletter-september-2021-2/

[xxxix] https://www.cet.energy/2021/09/15/china-energy-policy-newsletter-september-2021-2/
[xl] https://usercontent.one/wp/www.cet.energy/wp-content/uploads/2023/01/CET_Overview-of-the-Spot-Power-Market-Rules-Draft_December-2022.pdf
[xli] https://www.ndrc.gov.cn/xxgk/zcfb/tz/202201/t20220128_1313653.html?code=&state=123
[xlii] https://usercontent.one/wp/www.cet.energy/wp-content/uploads/2022/08/CET_China-Energy-Policy-Newsletter_August-2022.pdf
[xliii] http://www.sgcc.com.cn/html/sgcc_main/col2017021449/2021-11/24/20211124110318688580904_1.shtml
[xliv] https://www.oxfordenergy.org/wpcms/wp-content/uploads/2023/02/Assessing-Chinas-power-sector-low-carbon-transition-a-framing-paper-CE4.pdf
[xlv] https://www.ideacarbon.org/news_free/57940/
[xlvi] https://www.ndrc.gov.cn/xxgk/zcfb/tz/202212/t20221222_1343756.html
[xlvii] This data illustrates total grid investments, only a fraction of which are likely dedicated to purpose-built UHV lines for transmitted renewable power. For context, in the second half of 2022, China's State Grid claimed it would invest CNY22bn in UHV, approximately 20% of the 2022 full year investment figure. https://www.reuters.com/business/energy/chinas-state-grid-invest-22-bln-ultra-high-voltage-power-lines-report-2022-08-03/
[xlviii] http://energy.people.com.cn/n1/2020/1216/c71661-31968207.html
[xlix] https://www.spglobal.com/commodityinsights/en/market-insights/latest-news/energy-transition/092322-china-could-exceed-renewables-generation-target-of-33-by-2025
[l] http://www.sasac.gov.cn/n2588025/n2588124/c17342704/content.html
[li] https://www.jiemian.com/article/5744192.html
[lii] https://chinadialogue.net/en/energy/untangling-the-crossed-wires-of-chinas-super-grid/
[liii] http://www.sasac.gov.cn/n2588025/n2588124/c17342704/content.html
[liv] http://www.csee.org.cn/pic/u/cms/www/201912/04100423vh6e.pdf
[lv] https://chinadialogue.net/en/energy/untangling-the-crossed-wires-of-chinas-super-grid/
[lvi] https://energyandcleanair.org/wp/wp-content/uploads/2023/02/CREA_GEM_China-permits-two-new-coal-power-plants-per-week-in-2022.pdf
[lvii] https://m.in-en.com/article/html/energy-2320290.shtml
[lviii] The exact terminology used in the publication is the 'equivalent utilisation factor', which is a measure of utilisation after accounting for the availability rate.
[lix] https://news.bjx.com.cn/html/20221109/1267438.shtml
[lx] https://zfxxgk.ndrc.gov.cn/web/iteminfo.jsp?id=18212&code=&state=123
[lxi] http://paper.people.com.cn/zgnyb/html/2021-02/01/content_2032512.htm
[lxii] http://zfxxgk.nea.gov.cn/auto84/201607/t20160704_2272.htm
[lxiii] http://zfxxgk.nea.gov.cn/auto84/201608/t20160805_2285.htm?keywords=
[lxiv] https://www.sciencedirect.com/science/article/pii/S0921344918301137
[lxv] https://iea.blob.core.windows.net/assets/fd886bb9-27d8-4d5d-a03f-38cb34b77ed7/China_Power_System_Transformation.pdf
[lxvi] https://iea.blob.core.windows.net/assets/fd886bb9-27d8-4d5d-a03f-38cb34b77ed7/China_Power_System_Transformation.pdf
[lxvii] https://pdf.dfcfw.com/pdf/H3_AP202207041575739124_1.pdf?1656929235000.pdf
[lxviii] https://pdf.dfcfw.com/pdf/H3_AP202201171540919700_1.pdf?1642415253000.pdf
[lxix] https://www.ndrc.gov.cn/xxgk/zcfb/ghwb/202203/t20220322_1320016.html?code=&state=123
[lxx] https://news.bjx.com.cn/html/20221123/1271002.shtml
[lxxi] https://guangfu.bjx.com.cn/news/20220923/1256876.shtml & https://news.bjx.com.cn/html/20221018/1261851.shtml https://news.bjx.com.cn/html/20221124/1271297.shtml
[lxxii] https://www.ndrc.gov.cn/xxgk/zcfb/tz/202111/P020211103333054582799.pdf
[lxxiii] In our modelling, we conservatively assume that capital costs for retrofitting are CNY 600/KW (c.US$ 90/KW)
[lxxiv] We assume a decrease in operational efficiency of 14gce/KWh. Link: http://www.nrdc.cn/Public/uploads/2022-07-18/62d4c2e313df1.pdf
[lxxv] https://www.efchina.org/Attachments/Report/report-lceg-20211020/%E4%B8%AD%E5%9B%BD%E7%85%A4%E7%94%B5%E6%88%90%E6%9C%AC%E4%B8%8E%E9%A3%8E%E9%99%A9%E5%88%86%E6%9E%90.pdf
[lxxvi] For non-retrofitted units, we assume that capacity factors decline at an average annual rate of 1.2%, equivalent to the historical 10 year compound average growth rate; for retrofitted units, we assume capacity factors decline at twice this rate, stabilising at a capacity factor half of 2022 levels. In the counterfactual scenario, we assume that retrofitted units do not see expedited declines in capacity factors relative to the rest of the fleet.
[lxxvii] https://news.bjx.com.cn/html/20221124/1271297.shtml
[lxxviii] https://www.spglobal.com/commodityinsights/en/ci/research-analysis/chinas-ancillary-services-paradigm-shift-market-rules-adapt.html
[lxxix] This calculation was based on total 1H2019 AS revenues of CNY13bn, implying annual 2019 revenues of 26bn.
[lxxx] https://pdf.dfcfw.com/pdf/H3_AP202109061514540861_1.pdf?1630923186000.pdf
[lxxxi] https://pdf.dfcfw.com/pdf/H3_AP202202281549660634_1.pdf?1646044581000.pdf
[lxxxii] http://www.shandong.gov.cn/art/2020/6/2/art_107851_107306.html
[lxxxiii] https://twitter.com/YanQinyq/status/1580809026488918016
[lxxxiv] https://news.bjx.com.cn/html/20221117/1269728.shtml

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