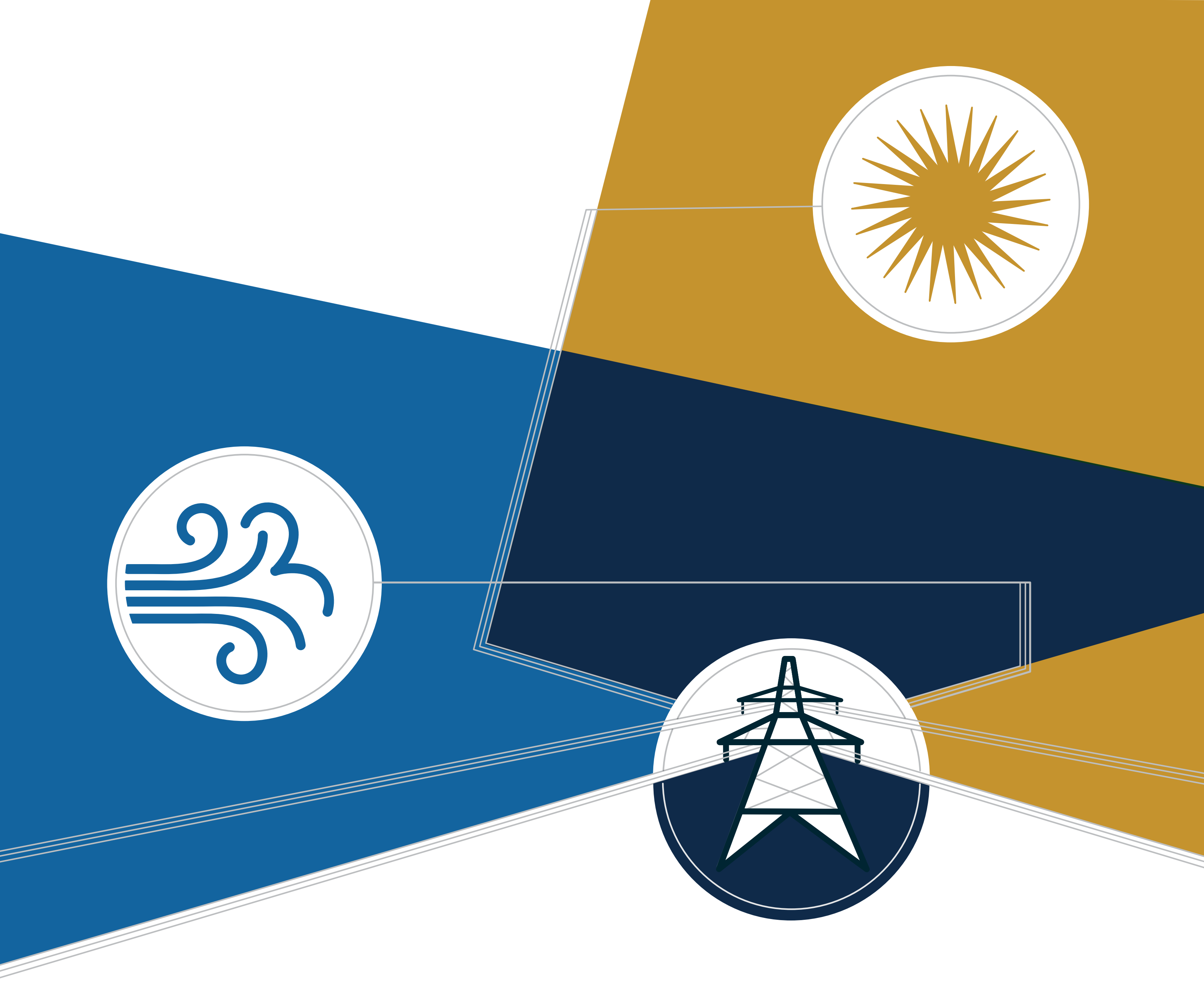

Renewable Energy Pathways to Carbon Neutrality in China

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POWER TRANSFORMATION LAB

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About the California-China Climate Institute:

The California-China Climate Institute was launched in September 2019 and is a University of California-wide initiative housed jointly at UC Berkeley's School of Law (through its Center for Law, Energy, and the Environment) and the Rausser College of Natural Resources. It is chaired by Jerry Brown, former Governor of the State of California, and vice-chaired by the former Chair of the California Air Resources Board Mary Nichols. The Institute also works closely with other University of California campuses, departments, and leaders. Through joint research, training, and dialogue in and between California and China, the Institute informs policymakers, fosters cooperation and partnership, and drives climate solutions at all levels.

About the Power Transformation Lab:

The Power Transformation Lab at the University of California, San Diego studies the engineering and institutional requirements to deploy low-carbon energy at scale. We work with academic, government, civil society, and industry partners to advance research and solutions to the climate challenge centering on the role of the power grid. Our areas of focus include renewable energy resource planning, affordable and reliable low-carbon power markets, and the political economy of industrial policy and low-carbon transitions in firms.

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The Institute of Energy, Environment and Economy, Tsinghua University (3E), established in 1980, is an interdisciplinary research and education institute at Tsinghua University. The institute's mission is to create, develop and disseminate the knowledge, ideas, and methodologies crucial for building sustainable energy systems and mitigating climate change for China and the world. As an important think tank for China's energy and climate change research, the institute has been continuously providing policy advisory services to the National Development and Reform Commission (NDRC), the Ministry of Ecology and Environment (MEE), and the National Energy Administration (NEA). The institute has long-time collaborations with prestigious universities and international organizations.

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SUMMARY FOR POLICYMAKERS

China has announced ambitious climate policy goals of reaching peak carbon emissions by 2030 and carbon neutrality by 2060.[1] To achieve these goals, it is crucial to decarbonize the largest carbon-emitting source, the power sector, which further enables the electrification of other sectors such as transportation, industry, and buildings. This process requires a large increase in low-carbon renewable energy and complementary infrastructure, including storage and transmission. While these long-term objectives are clear, the deployment structure, pace, and distributional impacts are uncertain. To address this gap, we developed a novel modeling approach with a high spatial and temporal resolution to identify feasible and efficient pathways for deploying renewables, storage systems, and transmission lines, by decade, from 2020 to 2060.[2] From a policy-making perspective, understanding low-carbon pathways provides national and subnational governments information needed to anticipate, plan for, and address a wide range of bottlenecks that will arise with this unprecedented transformation. Our analysis helps support a more effective, efficient, and equitable clean energy transition for China.

SPM Table 1 | Deployment Priorities Across Decades

<table>
<tr><th></th><th>Utility-scale solar</th><th>Distributed solar</th><th>Onshore wind</th><th>Offshore wind</th><th>Storage</th><th>Transmission lines</th></tr>
<tr><td>2020-2030</td><td colspan="2">Deploy in high-quality regions in the north and west</td><td rowspan="2">Deploy in northern regions and coastal regions</td><td rowspan="2">Ensure deployment efforts are sufficient in driving down costs in spite of unfavorable economics</td><td>Deploy in high-variable renewable energy regions to manage diurnal variations</td><td>Expand three regional clusters (northwest, south, and north)</td></tr>
<tr><td>2030-2040</td><td colspan="2">Extend to major load centers driven by continuous renewable cost declines</td><td rowspan="3">Prioritize battery storage in regions with limited hydro resource availability while promoting further battery cost declines</td><td>Strengthen major north-south corridors through both central and eastern regions</td></tr>
<tr><td>2040-2050</td><td rowspan="2">Largely exploit the available land near major load centers and continue the expansion in northern and western regions due to increasing land use and coal phasedown</td><td rowspan="2">Prioritize coastal regions due to proximity to load centers driven by lower transmission and integration costs</td><td rowspan="2">Prioritize coal-rich regions in the north to coordinate with the phasedown of coal plants</td><td rowspan="2">Ramp up deployment in coastal regions due to rapid cost declines</td><td rowspan="2">Expand both interprovincial networks and long-distance national networks to accommodate renewable integrations</td></tr>
<tr><td>2050-2060</td></tr>
</table>

1 United Nations, 2020

2 Zhang et al., Under Review

Energy Transition: Structure and Pace

The annual capacity additions of wind and solar will need to increase from around 70 gigawatts (GW) per year in the first decade (2020-2030) to 210-300 GW per year in the last decade before its carbon neutrality goal (2050-2060), while total installed capacities reach 2100-3200 GW by 2040, 3300-4800 GW by 2050, and 5200-5300 GW by 2060. Integrating these variable energy resources into the grid requires storage and transmission lines to address inter-regional imbalances and inter-temporal variations. Annual storage additions increase from 105-173 gigawatt hours (GWh) per year in the first decade to 180-260 GWh per year in the last decade, while the transmission network expands at rates of 13-16 GW/year (2020-2030), 13-38 GW/year (2030-2040), 18-24 GW/year (2040-2050), and 5-35 GW/year (2050-2060). Historical rates of manufacturing capabilities are likely to be sufficient to meet domestic demand, though crucially depending on the scale of clean energy technology exports.

Geographic Distribution

The geographical distributions of different technologies over four decades are highlighted in Summary For Policymakers (SPM) Table 1. Our results demonstrate, under feasible and efficient pathways, that utility-scale and distributed solar will start in the north and west regions of the country due to higher capacity factors, and then extend to major demand centers starting from the next decade (2030-2040). This shift is largely driven by renewable cost declines and high transmission costs. Notably, distributed solar will be more prominent along the coast since the costs will become similar to western regions over time. In addition, onshore wind has a wide footprint both in northern China and along the coast, while continuous cost declines will incentivize the deployment of offshore wind in coastal provinces. Relatively high transmission costs drive renewable deployment in lower-quality regions such as eastern China, but low-cost storage alters this dynamic by allowing renewable deployment in high-quality regions such as northern China in later decades. This suggests that regional prioritizations and renewable targets at the provincial level will be valuable for guiding local governments and sustaining the current deployment momentum.

Land Use, Economic Impacts, and Electricity Market Challenges

Solar deployment will exhaust the majority (51-82%) of suitable land in eastern provinces by 2060, while wind will significantly impact coastal province lands (14-48%), driven by promising renewable energy potentials and proximity to demand. While further guidance on siting and permitting from the national government is needed, local governments should establish project pathways and regional standards for co-location uses to reduce project uncertainties and mitigate land use impacts. Furthermore, as the transmission network becomes more interconnected, the total trading volume will likely see a three-fold increase by 2060. Efficient inner- and inter-regional trading mechanisms are thus essential in integrating renewables and reducing system costs.

Policy Recommendations

National and subnational governments have a strong role to play in achieving China's clean energy transition. To address large challenges and uncertainties, we identify near- and long-term priorities to design and implement supporting policy programs to ensure goals are met over time. The recommendations are highlighted in SPM Table 2.

SPM Table 2 | Policy Recommendations		
	National Government	**Provincial Governments**
Near-term (2020-2035)	• Incorporate and enforce clear deployment targets or portfolio standards in the upcoming five-year plans for renewable energy • Integrate storage and transmissions into the renewable planning processes with specific deployment targets • Set standards for regional electricity markets to allow more efficient power trading and balancing	• Promote retail and wholesale market reforms (e.g., time-of-use pricing, spot market trading) to improve renewable project economics • Identify strategies to facilitate coal retirement and mitigate local financial and social impacts
Long-term (2035-2060)	• Provide national guidance on renewable siting and permitting processes • Develop proper compensation mechanisms mainly for flexible conventional resources, and ensure continuous cost declines of renewables via auctions	• Monitor global markets for wind and solar equipment to ensure a sufficient supply to meet deployment targets • Establish project pathways and regional standards on installing renewables on agricultural lands • Strengthen effective compensation mechanisms to facilitate the least-cost deployment options for distributed energy resources

1. INTRODUCTION

China is the world's largest greenhouse gas (GHG) emitter and has announced ambitious climate policy goals of reaching peak carbon emissions by 2030 and carbon neutrality by 2060.[3] To achieve these goals, it is crucial to decarbonize the largest carbon-emitting source, the power sector, which further enables the electrification of other sectors such as transportation, industry, and building. As most of the carbon emissions from the power sector come from burning coal and natural gas, replacing carbon-intensive fossil fuels with low-carbon renewable energy and complementary infrastructure is key to decarbonizing the power sector.

Despite these clear long-term directions, there is uncertainty about the pace, structure, and distributional impacts of the transition to a net-zero future. The pace indicates how quickly we should reduce carbon emissions and replace fossil fuels with renewables, while the structure refers to which technologies are deployed over time and in which regions. Fossil fuel retirement and the deployment of renewables, transmission, and storage affect how costs and benefits will be distributed across regions and interest groups, which in turn alter the feasibility and equity of various pathways to carbon neutrality. This study seeks to uncover feasible and efficient pathways to carbon neutrality for China's power sector with sufficient granularity to assess the uncertainties of renewable deployment rates, geographical distributions, and land uses.

Several studies have examined China's power sector as snapshots in future years, e.g., power system optimization models of renewable energy deployment and transmission expansion in 2030,[4] 2050,[5,6] and 2060.[7] Snapshot analyses are useful to specify an optimal end-state, but they do not consider potential uneven distributions and bottlenecks of renewable and transmission buildout across time. In comparison, studies using integrated assessment models identify pathways to deep decarbonization by around mid-century, but lack spatial resolution and grid operational details to explore localized impacts of the transition.[8,9]

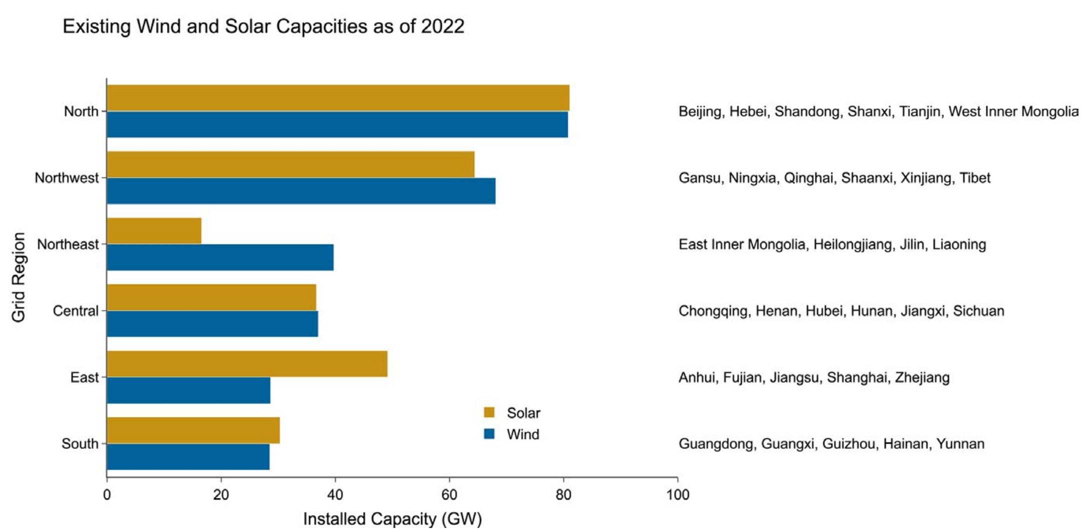
As regions have different existing fossil fuel capacities and will deploy renewable energy at different rates, the transition away from fossil fuels will not affect all regions equally and over time. Similarly, if regions only see huge renewable additions in later periods, they might not have the institutional capacity in place to deploy and integrate renewable energy into the grid while meeting grid reliability requirements. Furthermore, periods of rapid expansion of infrastructure must be able to be met via manufacturing and project development capacity, and could have important implications for land use. In this study, we aim to bridge this gap by calculating sequential pathways to carbon neutrality for China's power sector from 2020 to 2060 with decadal resolution. From a policy-making perspective, understanding potential low-carbon pathways provides national and subnational governments the information needed to anticipate, plan for, and address a wide range of constraints that will arise with this unprecedented transformation. Our analysis helps support a more effective, efficient, and equitable clean energy transition for China.

3 United Nations, 2020
4 He et al., 2020
5 Chen et al., 2021
6 Zhuo et al., 2022
7 Zhang et al., Under Review
8 Duan et al., 2021
9 He et al., 2022

2. RENEWABLE ENERGY TRENDS AND POLICY

China is the world leader in renewable energy deployment. As of 2022, China has installed 365 gigawatts (GW) of wind and 390 GW of solar, as recent years have seen unprecedented rates of new additions—40 GW of wind and 52 GW of solar per year on average for the past five years.[10] The installed wind and solar capacities are primarily located in the "three north" regions while the east coast also has a growing solar footprint (Figure 1). There is a fundamental mismatch between some of the high-quality resources and major electricity demand centers, which are located along the coast (e.g., Shandong, Guangdong, and Jiangsu), primarily driven by high population densities and economic development. Provinces in the north and west have the best quality solar resources due to high annual irradiations (e.g., Qinghai, Gansu, and Inner Mongolia), while provinces in the north and along the coast have high-quality wind resources (e.g., Gansu, Inner Mongolia, and Jiangsu). In addition, wind and solar capacities are mostly equal in each region, with the exceptions of the northeast and east.

Figure 1 | Installed Wind and Solar Capacities Across Grid Regions as of 2022



Source: China Electricity Council, 2023.

China's renewable energy growth is driven by a set of government policies focusing on manufacturing, increasing adoption rates, and market reforms.[11,12] The 14th Five-Year Plan (2021-2025) (FYP) for Renewable Energy sets a target to deploy at least 1,200 GW of wind and solar by 2030, and promotes the development of complementary infrastructure including storage systems and transmission lines.[13] To address previous challenges such as high renewable curtailments, grid operation inefficiencies, and grid connection delays,[14,15] the Chinese government issued energy market reforms in 2015, featuring new market participation rules and electricity pricing mechanisms.[16]

10 China Electricity Council, 2023
11 Guo et al., 2020
12 Nahm, 2017
13 National Development and Reform Commission, 2021a
14 International Energy Agency, 2018
15 Lu et al., 2016
16 State Council, 2015

Accelerated renewable deployment will likely intensify concerns around renewable integration and land use. Although the 14th FYP set deployment targets and regional focuses for storage and transmission, there has been minimal effort to translate targets to specific projects with spatial granularity. Project-specific requirements are essential to preemptively remove institutional barriers, and ensure that complementary infrastructure keeps pace with renewable deployment. Furthermore, recent land use policies have escalated uncertainties in renewable deployment. The 14th FYP highlighted the installation of distributed generation on various land use types, but project implementation can face more stringent local standards or inadequate information, regarding land use restrictions and classifications of potential project sites. These evolving challenges can delay renewable deployment and impact system costs if not properly addressed.

Considering the aforementioned policy gaps, we explore decadal pathways from 2020 to carbon neutrality in 2060 with a focus on several questions: (1) What structures and paces are required for the deployment of renewables, storage, and transmission? (2) What are the geographical distributions of different technologies across decades? and (3) What are the land use impacts across regions over time? The answers to these questions will help strengthen the understanding of implementation priorities both in the near- and long-term, as well as the supporting policies that are required to achieve China's climate policy goals.

3. METHODS

We develop a high-resolution power system planning and operation model to simulate China's power sector in each decade.[17] The model optimizes the amount and location of variable renewable energy (VRE), storage systems, and transmission lines at the lowest cost, while satisfying provincial hourly electricity demands, grid reliability, and land use constraints, among other requirements, for a whole year of operation. The objective of each simulation is to minimize the total annualized costs of investment and generation dispatch. We adapt this model to evolving power system conditions and input assumptions by sequentially linking the outputs of each decade. The combined model outputs across periods identify feasible and efficient pathways for renewable deployment from 2020 to 2060 (Figure 2). Further information on modeling inputs and methodology is provided in the Appendix.

The geographic resolution is given by renewable resource availability computed from the Goddard Earth Observing System Model (GEOS-5).[18] GEOS-5 provides hourly simulation data of atmospheric properties including temperature, wind speeds, and solar irradiance at a spatial resolution of approximately 31 by 25 kilometers per cell. We consider a wide range of land suitability assumptions, such as preferences for low slopes and altitudes and for certain land types with fewer competing uses. For example, the National Energy Administration and other ministries have issued land use regulations that restrict solar deployment on productive agricultural lands, where we assume only a small fraction (2-20%) is available for solar, while wind can be deployed on most (80-100%) of the croplands, grasslands, shrublands, and barren lands.[19]

Table 1 | Model Scenario Descriptions

Scenario name	Description	Renewable cost evolution	Coal retirement schedule
Baseline	Emission targets are based on the Tsinghua ICCSD 2ºC scenario. More optimistic cost declines in renewable energy. Coal plants have 40 years of lifespan, and CCS retrofits start in 2030.	Optimistic	Normal
Conservative Cost Declines	More conservative cost declines in the capital costs of renewable energy, consistent with percentage decreases from NREL Annual Technology Baseline.	Conservative	Normal
Accelerated Coal Retirement	Accelerated coal retirement schedule assuming more stringent policy targets are enforced. Coal plants have 30 years of lifespan, and CCS retrofits start in 2040.	Optimistic	Accelerated

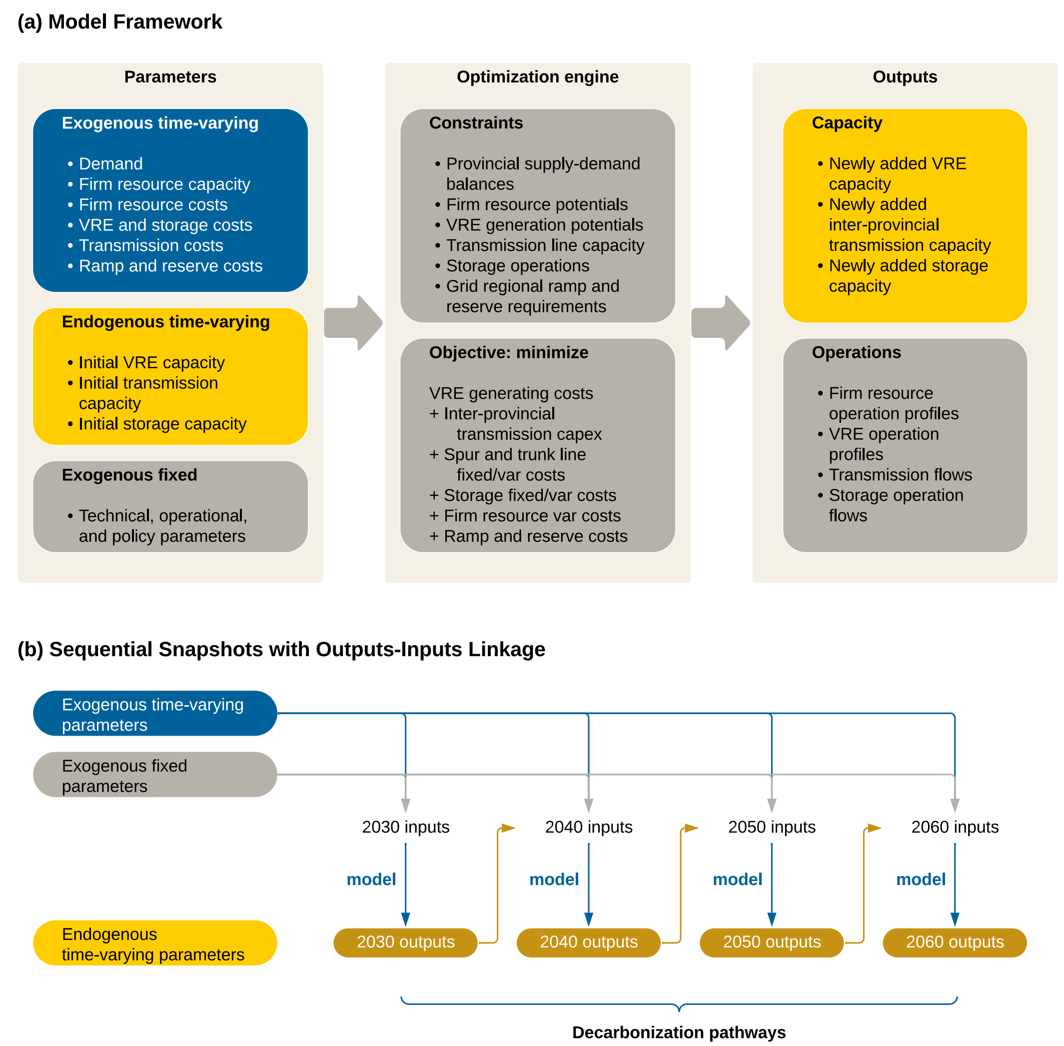
The model considers four types of VRE technologies (i.e., onshore wind, offshore wind, utility-scale solar, distributed solar), two types of storage systems (i.e., pumped hydro storage, battery storage), and three types of transmission lines (i.e., spur lines, trunk lines, and inter-provincial lines). Spur lines and trunk lines connect wind and solar to the high-voltage grid and are factored

17 Zhang et al., Under Review

18 NASA, 2010

19 National Energy Administration, 2017

Figure 2 | Modeling Framework for Decarbonization Pathways of China's Power Sector



The modeling framework in panel (a) includes model parameters, constraints, objectives, and outputs. Panel (b) shows the outputs-inputs linkage between sequential snapshots. Exogenous parameters are fed into each model run, and model outputs of one run are used as inputs for the next run.

into the costs of deployment per cell. Provincial investments and hourly generation dispatch decisions and inter-provincial electricity transfers are obtained from the simulation outputs.

Each model run includes exogenous parameters obtained from relevant modeling studies and policy documents. We fix the firm resource capacities in each decade according to various growth assumptions and restrict fossil fuel emissions to be consistent with a 2°C global average temperature rise target.[20] We further let power become a net emission sink with 550 million tons of negative carbon emissions in 2060 to offset emissions from other sectors. In addition, we allow carbon capture and sequestration (CCS) for natural gas and coal power plants to reduce carbon intensity, considering partial capture rates.

We design three scenarios of the evolution of renewable costs and the retirement schedule of coal plants (Table 1) to evaluate the robustness of our findings. In the Baseline Scenario, we adopt an optimistic cost decline trajectory relative to the 2020 level for the capital costs and operation costs of wind, solar, and storage in the context of the Chinese market. In the Conservative Cost Declines Scenario, we assume that the capital costs of wind, solar, and storage have slower price declines compared to the baseline scenario, based on technology-specific

[20] Tsinghua University, 2020

projections from the U.S. National Renewable Energy Laboratory.[21] In the Accelerated Coal Retirement Scenario, we assume that more stringent policy frameworks will be implemented to facilitate the retirement of coal plants.[22] Under this scenario, coal plants are expected to have 30 years of lifespan instead of 40 years under the baseline, and coal retrofitting for CCS only starts after 2040 compared to 2030 under the baseline. Across all three scenarios, we enforce a minimum 1,200 GW renewable deployment target by 2030 to be consistent with the current renewable energy policy programs.

[21] NREL, 2017

[22] Cui et al., 2022

4. KEY FINDINGS

4.1. Increasing renewable energy deployment rates

- Significant amounts of renewable energy and storage will drive a cleaner power generation mix over time.
- Increasing deployment rates are needed to meet the necessary installed capacities in each decade.
- In order to accelerate coal retirement, a faster renewable deployment pace is required.
- Given the historically high rates of manufacturing, existing capacity is likely to be sufficient to meet renewable energy production demand.

Our results show that a significant amount of wind, solar, and storage will be deployed in China across all decades under all the scenarios. Figure 3(a) shows nationwide installed capacities across scenarios. In the Baseline Scenario, wind capacity increases from 583 to 2201 GW, and solar capacity increases from 615 to 3174 GW from 2030 to 2060. Storage capacity, covering both 8-hour pumped hydro and 4-hour battery storage, increases four-fold from 1397 to 5930 gigawatt hours (GWh) from 2030 to 2060. By comparison, the Conservative Cost Declines Scenario has similar installed renewable and storage capacities, but the relative shares of renewable technologies change—in particular, distributed solar and onshore wind see higher installations. The Accelerated Coal Retirement Scenario deploys an additional 1052 GW of renewables and 1948 GWh of storage by 2040, and an additional 1303 GW of renewables and 2375 GWh of storage by 2050 as compared to the baseline, driven by a stronger need to replace the retired coal capacity during these two decades. Among storage technologies, battery storage is needed sooner in the Accelerated Coal Retirement Scenario than the baseline, as some regions run into the assumed limits on pumped hydro resources and need to use battery storage as an alternative.

Due to increasing renewable penetration rates, fossil fuel plays a less important role in China's power sector. Figure 3(b) shows the nationwide generation mix across scenarios. In the Baseline Scenario, the share of fossil fuels in the generation mix drops from 51% in 2030 to 35% in 2040, 19% in 2050, and 8% in 2060. By comparison, the share of wind and solar generation increases from 27% in 2030 to 39% in 2040, 49% in 2050, and 56% in 2060. The Conservative Cost Declines Scenario sees a similar generation mix to the baseline, while the Accelerated Coal Retirement Scenario implies a more important role of renewable energy in the generation mix. These conclusions are roughly in line with previous studies,[23,24,25] but provide decadal resolutions to the structure and pace required for the transition.

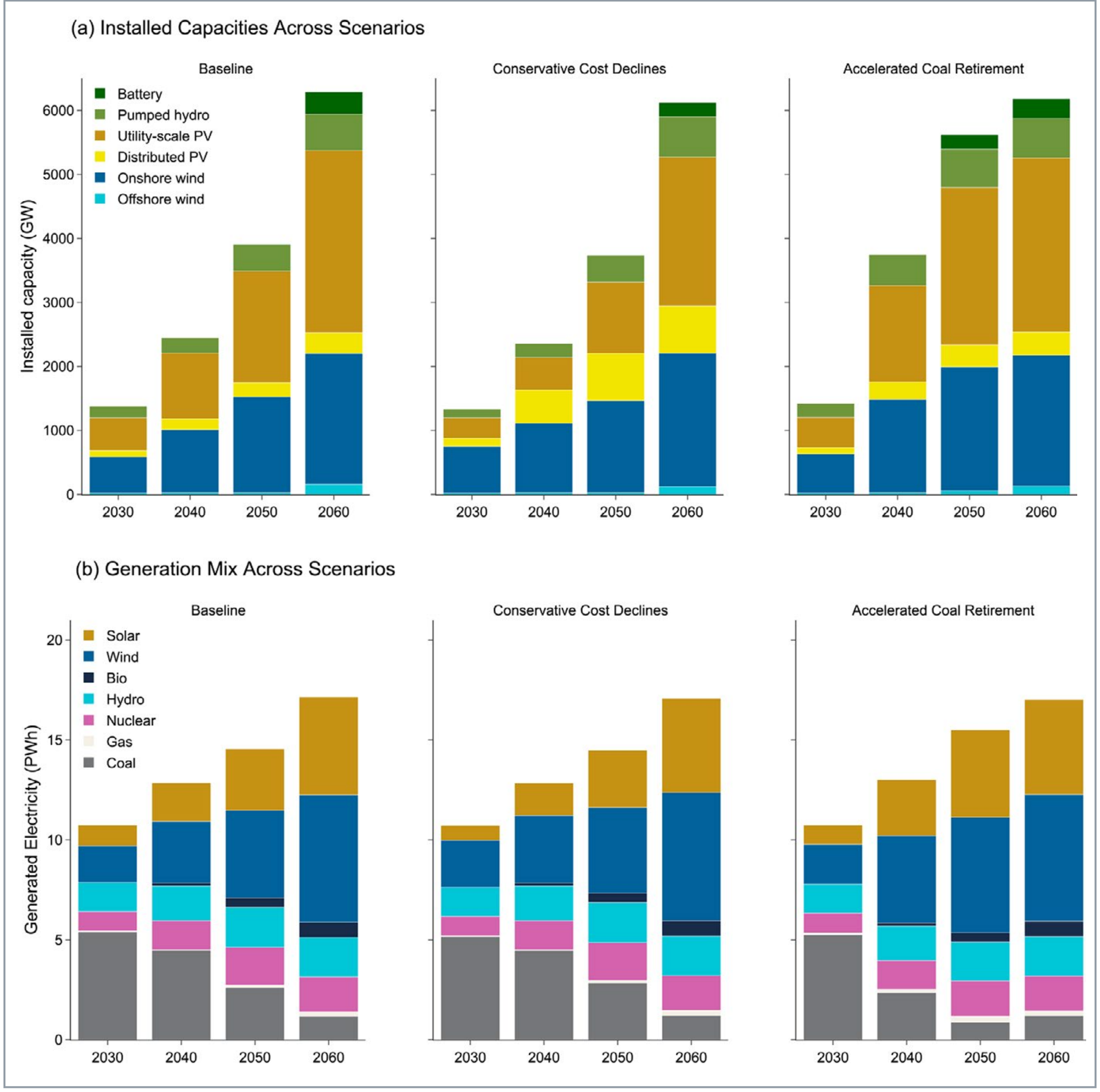
To reach the installed renewable capacities in each decade, our results show that the combined rate of capacity additions for wind and solar will need to increase from 70 GW per year in the first decade to 210-300 GW per year in the last decade across scenarios, assuming that all existing VRE capacity in 2020 will retire by 2045 and the newly built VRE has a lifespan of 25 years. On the other hand, historical rates of renewable capacity additions exceed near-term requirements. The past five years have seen an average renewable deployment rate of 92 GW

[23] Chen et al., 2021

[24] Khanna et al., 2021

[25] Zhuo et al., 2022

Figure 3 | Nationwide Installed Renewable Capacities and Generation Mix from 2030 to 2060



per year (40 GW per year for wind and 52 GW per year for solar).[26] Furthermore, on the supply side, manufacturing capacities for wind turbines and solar modules were estimated to be 80 GW and 264 GW per year in 2022, respectively, sufficient for handling domestic demands, though we do not model expected export demands.[27,28]

Moreover, to meet the storage deployment targets, our results show that the rate of storage capacity additions will need to increase from 105-173 GWh per year in the first period to 180-260 GWh per year in the last period across scenarios, assuming that the storage system has a lifespan of 15 years. However, historical rates of storage capacity additions, including both pumped hydro and battery storage, were only around 50 GWh in 2021.[29,30] On the supply side, China's manufacturing capacity for stationary battery storage systems was 130 GWh per year in 2022, approximately 10% of the total battery manufacturing capacity.[31] Assuming that manufacturing capacity for pumped hydro is sufficient, meeting long-term storage demands will likely be plausible across periods.

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26 China Electricity Council, 2023

27 International Energy Agency, 2022b

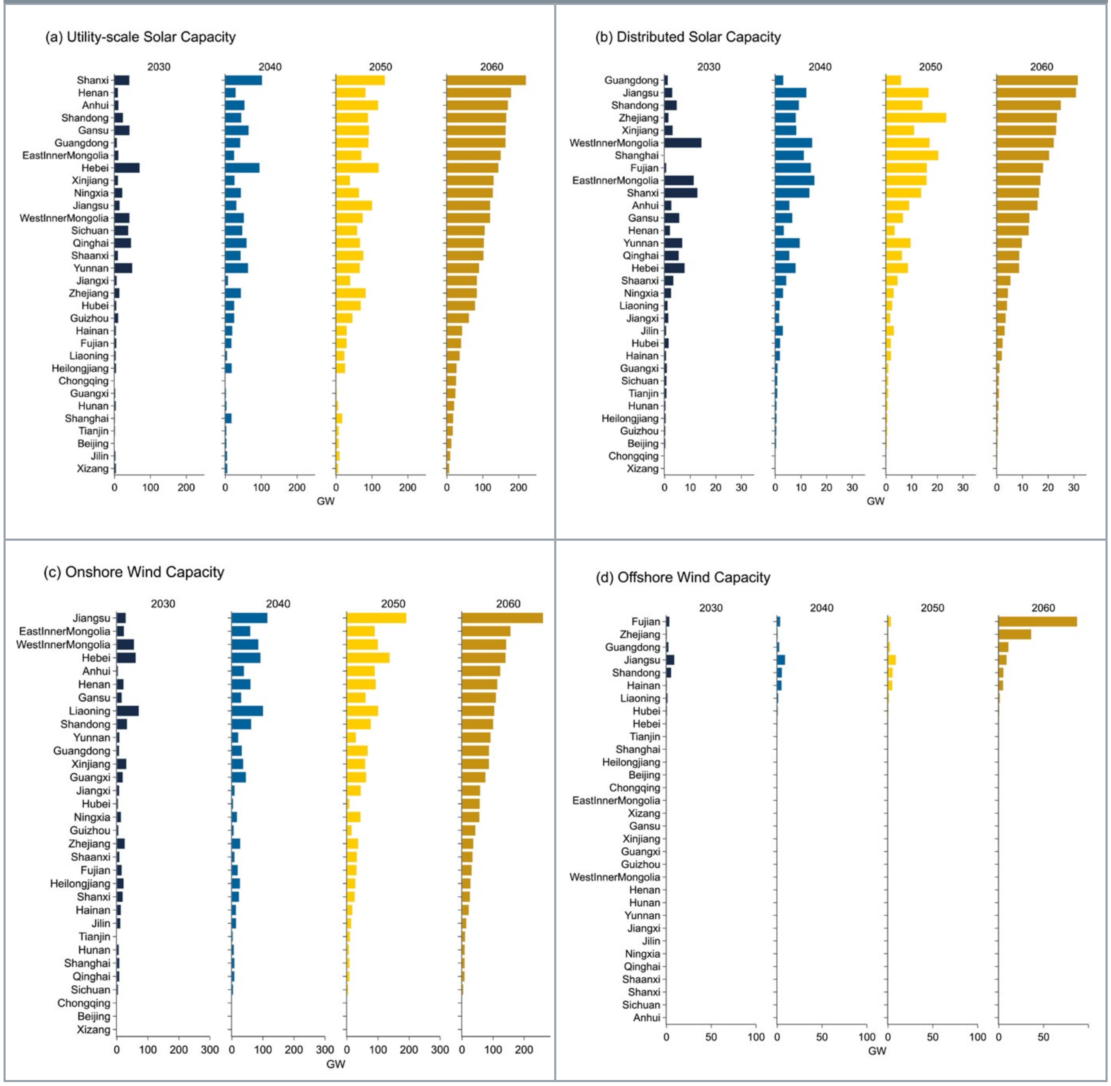
28 Wood Mackenzie, 2022

29 Energy Information Administration, 2022

30 International Energy Agency, 2022a

31 Wood Mackenzie, 2022

Figure 4 | Provincial-level Installed Solar and Wind Capacities from 2030 to 2060



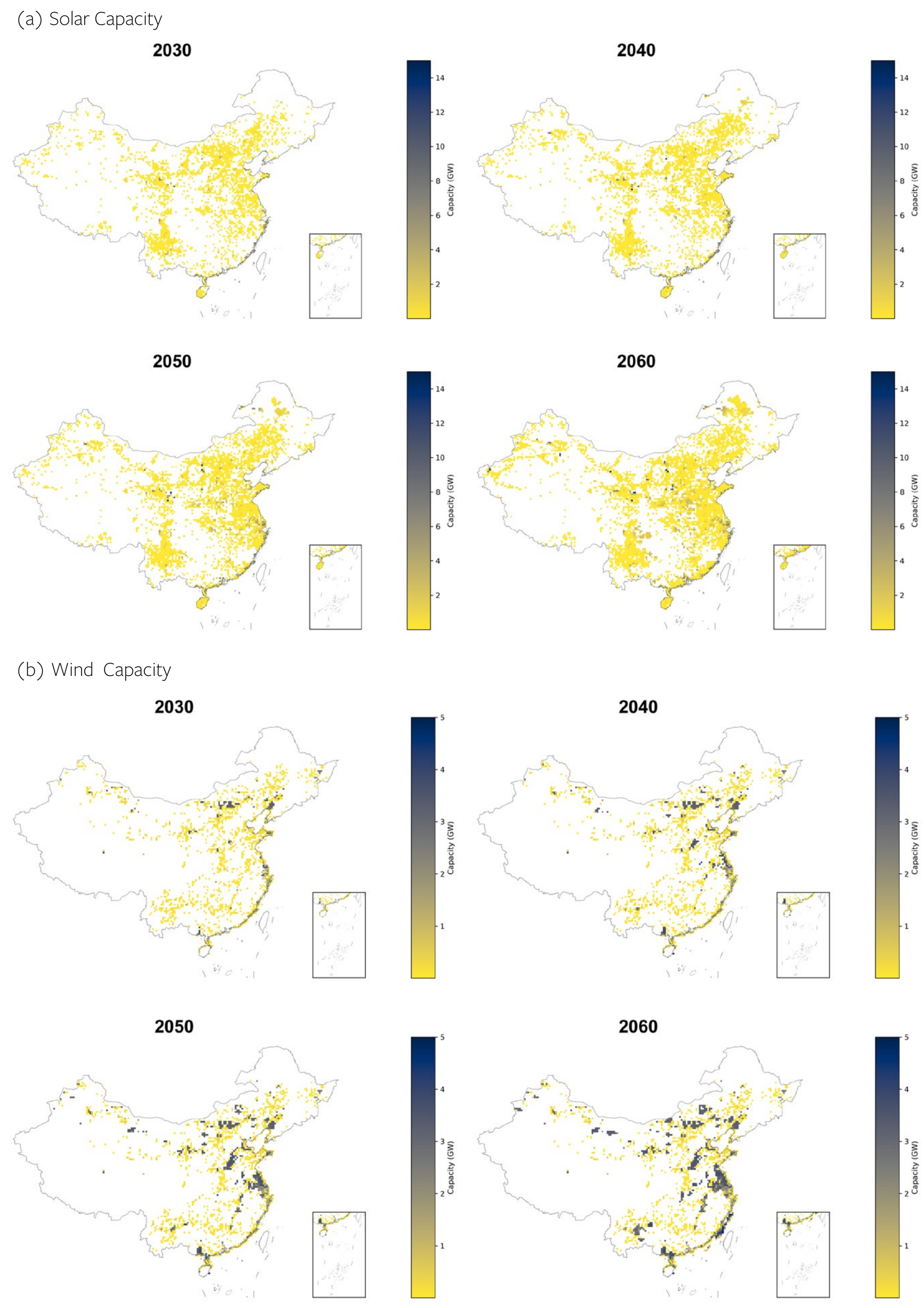
4.2. Regional distributions over time

- Under feasible and efficient pathways, utility-scale and distributed solar will expand from the north and west to major demand centers starting in the 2030s.
- Distributed solar will increase along the coast, due to lower transmission and integration costs.
- Onshore wind will expand in the north and along the coast, while continuous cost declines will promote the deployment of offshore wind in coastal provinces.
- Storage deployment is mainly correlated with provincial renewable capacities, in particular, solar capacity.

Total renewable installations are primarily driven by rising demand, coal retirement, and the availability of other firm resources, and are dependent on complementary storage and transmission expansion in each decade. Regions with low demand and high resource quality, such as the west and north, have renewable deployment and transmission expansion due to the need to export power. However, this need can be offset by the increasing renewable deployment in importing regions driven by cost declines.

Figure 4 shows the provincial-level installed VRE capacities from 2030-2060, and Figure 5 offers a detailed perspective at the cell level. In the first period (2020-2030), our results indicate that VRE will be deployed in regions with high capacity factors (CF) and thus low

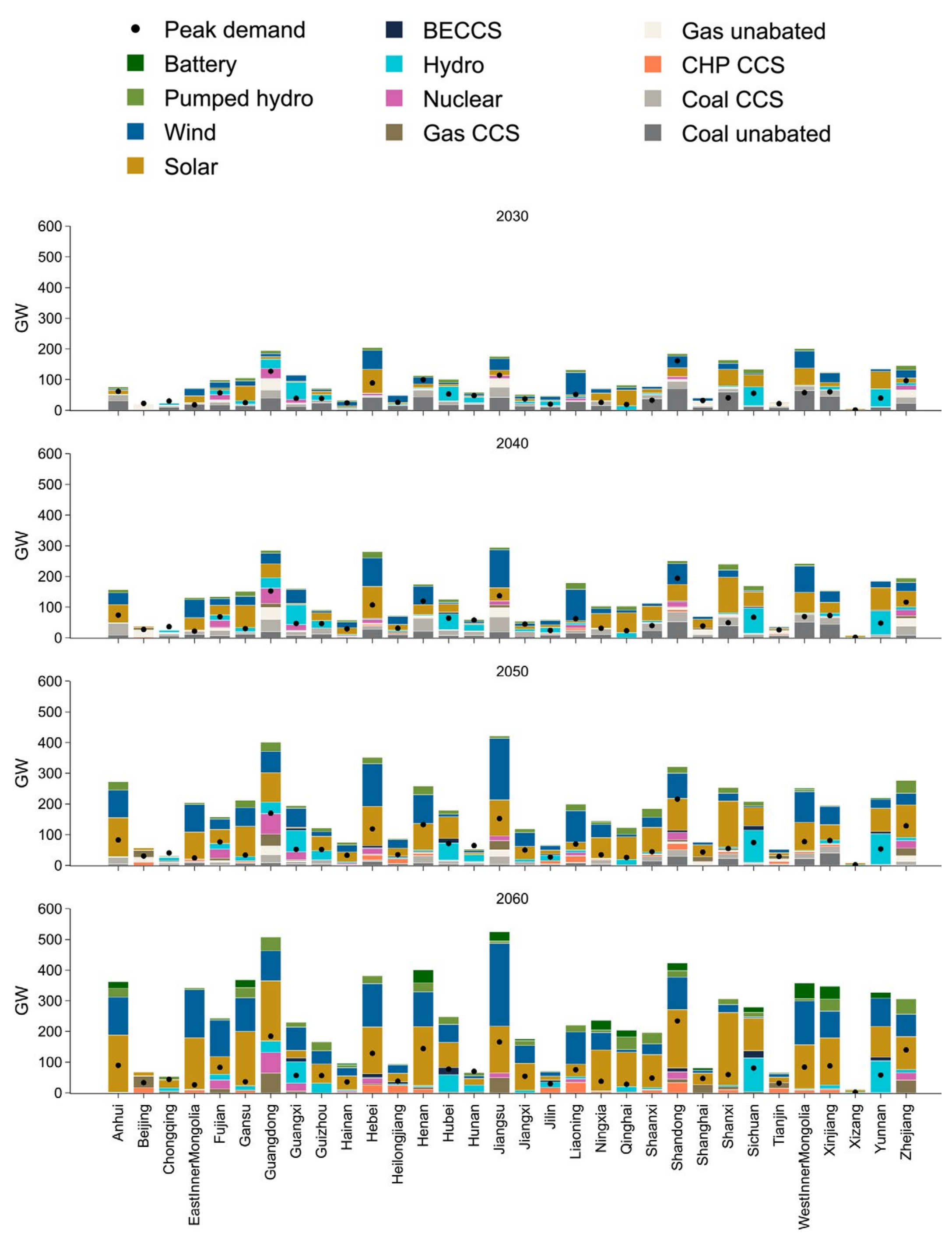
Figure 5 | Cell-level Installed Solar and Wind Capacities from 2030 to 2060



Note: Wind includes both onshore and offshore wind, and solar includes both utility-scale and distributed solar.

levelized cost of electricity (LCOE) from a least system cost perspective. CF measures the actual power generation as a fraction of the total theoretical potential generation at maximum output, and LCOE measures the discount rate-adjusted cost per unit of production over the lifetime of the plant. Utility-scale solar and distributed solar will be more concentrated in the west and north, while onshore wind will be deployed in both northern regions and major load

Figure 6 | Provincial Generation Capacities from 2030 to 2060



centers along the coast, in line with previous research that has examined early deployment trends.[32] Furthermore, results show that a limited amount of offshore wind will be built during the 2020s due to its assumed high capital costs relative to other technology types. The second period (2030-2040) sees the VRE deployment extend to lower-CF regions due to declining renewable costs and relatively high transmission expansion costs. Utility-scale solar and distributed solar continue to spread to major load centers, while wind deployment continues its previous trends in this decade. In the third period (2040-2050), continuous renewable cost declines will drive deployment in low-CF regions, but low-cost storage systems will alter this dynamic by allowing more economic development in high-CF regions facing higher

32 He et al., 2020

integration barriers. Distributed solar will have stronger prominence in regions along the coast in later periods despite having lower CFs, due to lower transmission and integration costs of locating close to demand. Utility-scale solar and onshore wind will have a large footprint in both major load centers and less land-constrained regions in the north and west. Overall, we can observe fewer regional disparities in solar deployment. The last period (2050-2060) sees a significant ramp-up in offshore wind deployment along the coast due to rapid cost declines. Other snapshot studies focusing on later periods find similar regional distributions by 2050 or 2060,[33,34] while this study presents the evolving dynamics over time and explains how we will likely reach these outcomes.

Using provincial results as an example, we can see that major demand centers have renewable deployment primarily in later periods, while high-quality regions see deployment across decades. For example, Henan, one of the major demand centers, will only have 9 GW of utility-scale solar in the first period (2020-2030) as compared to Inner Mongolia's 52 GW and Yunnan's 50 GW. However, Henan starts accelerating in the third period (2040-2050) and eventually has 180 GW of utility-scale solar by 2060. Another major demand center, Jiangsu, will develop 30 GW of onshore wind by 2030, and reach 262 GW by 2060. Inner Mongolia, a province with high-quality wind resources and significant deployment today will see large onshore wind installation across all decades with 79 GW by 2030 and 299 GW by 2060.

Figure 6 shows the provincial-level generation capacities for all generation technologies. Our results show that a majority of provinces will have total generation capacities far exceeding their peak demands, a common occurrence due to the limited and varying renewable energy capacity factors. Some provinces with limited renewable availability and a high dependency on electricity imports, such as Hunan, will have total generation capacities below peak demand levels in all later decades.

Storage deployment is mainly correlated with renewable capacities in each province, in particular, solar capacity. As mentioned earlier, storage systems play an increasingly important role in balancing the diurnal variations of VRE resources, and continuous storage cost declines allow more economic development in high-CF regions. If regions have net electricity exports driven by excess renewable capacity, storage capacity will likely be substituted by transmission lines for power balancing. Through comparing storage technology types, we can observe that pumped hydro storage is deployed in high-VRE regions at early stages, but can reach the assumed maximum deployment potential in regions with limited resource availability in later periods. By comparison, our results show that battery capacity is mostly needed in the latter stages of decarbonization. These findings are driven by the assumptions that battery storage still has high early-stage capital costs relative to pumped hydro storage, and the value of storage primarily stems from meeting resource adequacy requirements and smoothing out VRE generation. We do not explicitly model technological learning, and therefore still conclude that some early battery storage deployment efforts are essential to continue cost declines.

4.3. Expanded inter-regional transmission connections

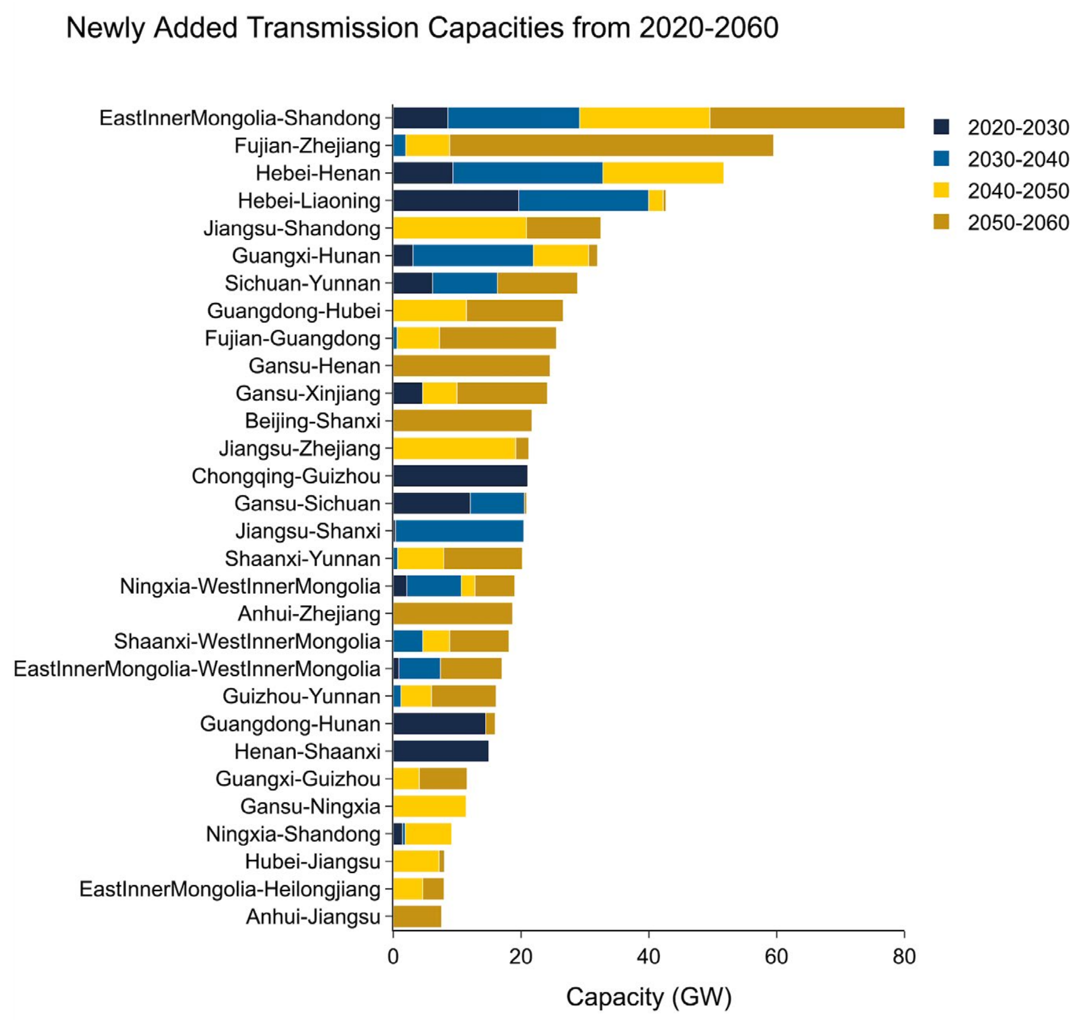
- The transmission network will expand to new regions and trading volumes will rise to accommodate renewable integration.
- Increasing transmission expansion rates will be required in the long term.

Our results indicate that transmission network expansion will experience regional shifts across time periods. Figure 7 shows the newly added transmission capacities from 2020-2060, while Figure 8 displays their geographical distributions. During the first decade, interprovincial connections will be strengthened in three regional clusters—northwest, south, and north. New transmission lines mostly connect low-demand/high-firm capacity regions to high-demand/low-firm capacity regions. Starting from the 2030s, major north-south corridors will be expanded to connect central and eastern regions with other regions. This shift is mostly

33 Chen et al., 2021

34 Zhuo et al., 2022

Figure 7 | Newly Added Transmission Capacity from 2020 to 2060



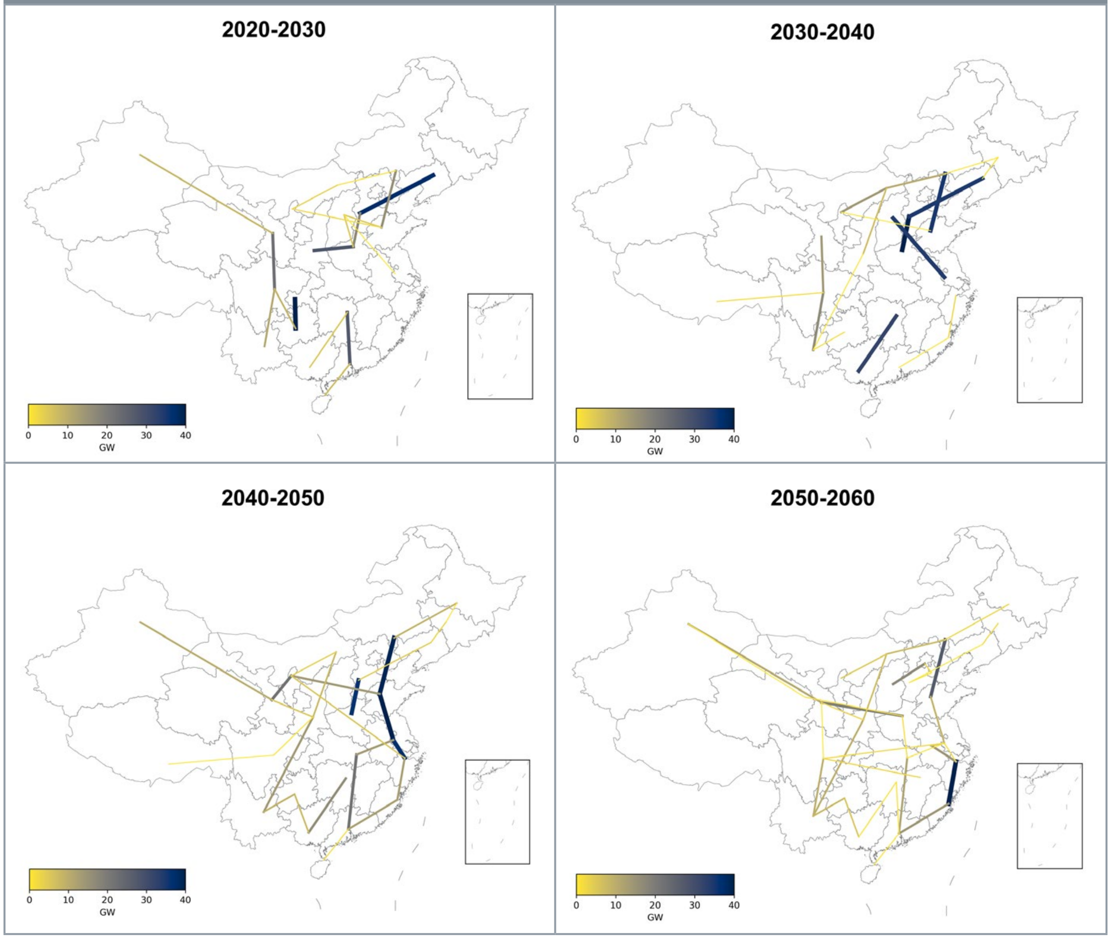
because it will still be more economical to deploy renewables and transmission lines in higher-quality regions. During the last two decades, transmission networks will be expanded across China due to rapid renewable deployment and coal phasedown in all regions. Accelerating coal retirement can speed up the transmission expansion to earlier stages to complement the renewable buildout.

Overall, total nationwide expansion rates of inter-provincial transmission capacity are 13-16, 13-38, 18-24, and 5-35 GW per year across decades, including both high-voltage and ultra-high-voltage lines. Considering that the past decade has seen ultra-high-voltage lines expand at a rate of approximately 16-20 GW per year, meeting the near-term transmission expansion requirements should be plausible.[35]

Results further show that total nationwide power flows will increase from 2.1 petawatt hour (PWh) in 2030 to 6.4 PWh in 2060. The share of power that flows in both directions, will increase from 8.2% to 8.8%, 12.2%, and 19.8% over the decades. On a regional level, the net exported amount from major exporters (northwest, northeast, and south) will increase from 527 TWh in 2030 to 1455 TWh in 2060, suggesting that regions will be more interdependent. As our model assumes that provinces can trade power freely up to total transmission interconnection capacities, neglecting operational and market frictions, the total traded volume may be overestimated.

[35] China Power, 2022

Figure 8 | Geographical Distributions of Newly Added Transmission Capacity from 2020 to 2060



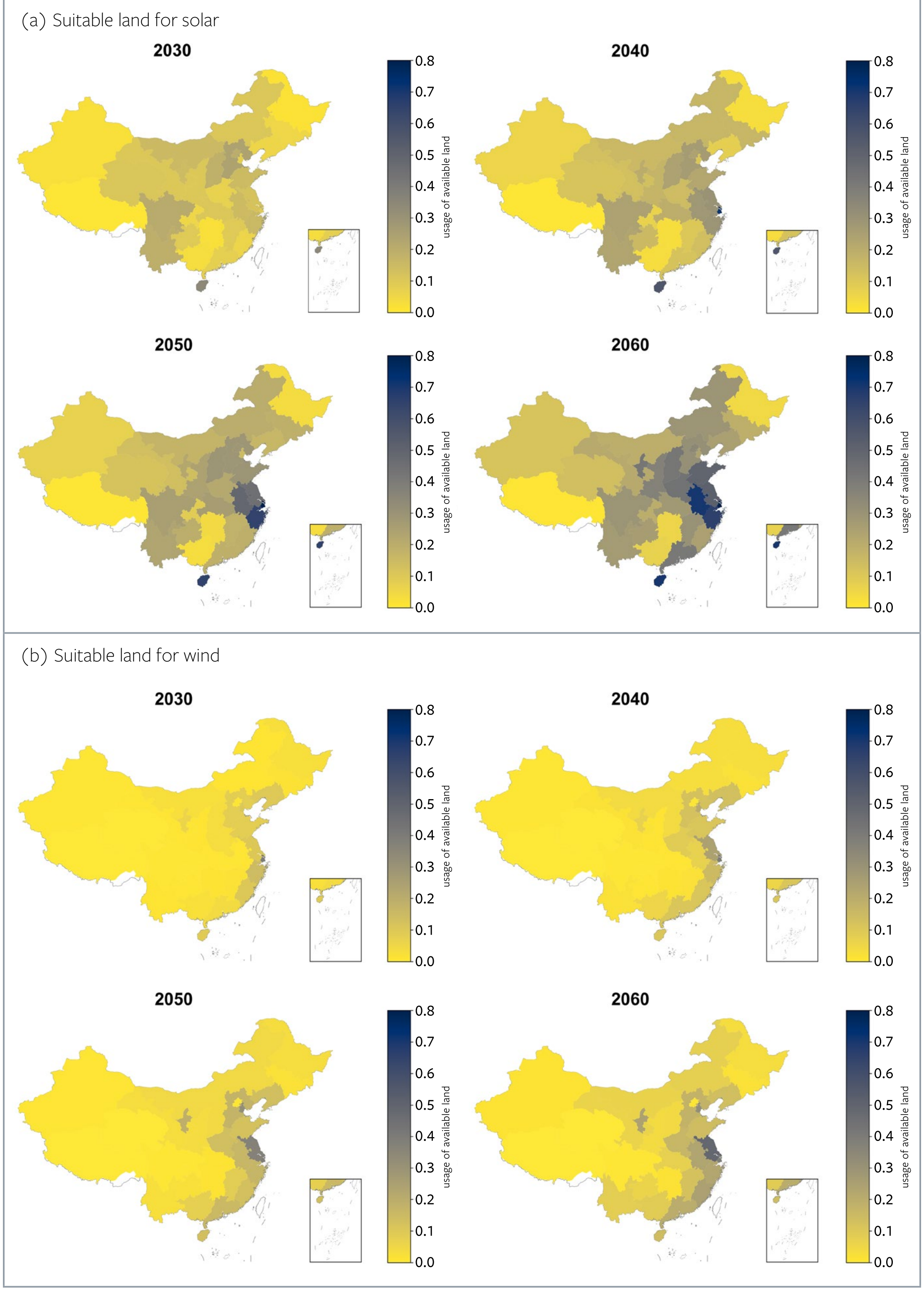
Tradeoffs between land use and transmission expansion also occur. First, even though the land is not exhausted in coastal regions at early stages, it is more economical to use high-quality resources in the north and west due to the relatively larger regional differences in LCOEs. Thus, as the results suggest, transmission lines will be built in the early stages to facilitate long-distance power balancing. As the costs of renewables further decline, coastal regions will ramp up renewable deployment, which partially offsets the need for further transmission expansion. Second, in later stages when the land is significantly exhausted in coastal regions, it will not be economical to use low-CF and high-LCOE cells for further deployment. Consequently, we can observe stabilized or slower renewable deployment paces in some of the coastal regions but with more transmission expansion.

4.4. More binding land use constraints

- Large-scale solar and wind deployment is land intensive, causing increasingly binding land use constraints on low-carbon goals.
- Solar deployment will experience a shift in most impacted regions from the west and north to eastern provinces, while wind deployment incurs land use pressure most prominently in coastal provinces.

As wind requires less land use per unit capacity and can be deployed on more types of land (including agricultural land), the deployment of wind has smaller land use impacts than that of solar. Figure 9 shows the fraction of suitable land for each renewable energy type that is utilized from 2030-2060. Solar deployment has an average usage of 11%, 19%, 24%, and 32% of suitable land in the nation from 2030 to 2060, meaning that by 2060, roughly one-third of the land that is suitable for solar has installed solar. The most impacted regions switch from the

Figure 9 | Percentage Shares of Suitable Land for Wind and Solar from 2030 to 2060



Note: Wind includes both onshore and offshore wind, and solar includes both utility-scale and distributed solar.

west and north in the first decade (21-24%) to the eastern provinces starting from the second decade (30-72%). In the last decade (2050-2060), the majority (51-82%) of suitable land for solar in eastern provinces will be exploited. By comparison, wind deployment impacts land use to a lesser extent than solar, and mostly in coastal provinces. The last decade will see 14-48% of suitable land exhausted for wind farms.

4.5. Misalignment between coal retirement and renewable deployment

- In most provinces, additional renewable capacity will exceed retired coal power capacity over time.
- However, there are still possible misalignments between renewable deployment and coal retirement in regions with early or delayed buildouts, indicating potential political economy challenges.

Coal retirement and renewable energy deployment proceed at different speeds across provinces. If regions have early or delayed renewable buildouts, there will be a misalignment between coal retirement and renewable deployment. As coal plants begin to retire in larger numbers, these can be associated with financial and social risks (e.g., stranded assets, job losses) without sufficient complementary policy support. In our results, northeastern provinces will have predominantly early-stage renewable deployment, leading to a 4.8 GW difference in retired coal and installed renewable capacities in the last decade. Similarly, central provinces will start deploying renewable in later stages and thus can see a gap of up to 8.7 GW in the first decades. Other regions, in comparison, will see renewable additions exceed the retired coal capacity across decades. Overall, maximum coal retirement rates on a provincial level can increase from 3.9 GW per decade in the first period to 9.1, 38.4, and 61.1 GW per decade in later periods. This requires greater efforts in coordinating coal retirement and renewable deployment, with a focus on coal-rich and low-renewable potential regions to reduce local opposition during the implementation of coal retirement programs. For instance, in Shanxi, there has been persistent resistance to coal retirement due to lack of assistance programs, as coal-related industries contribute significantly to employment and local government revenues. In the case of more stringent policy targets accompanied by accelerated coal retirement, the misalignment will likely be more exacerbated in regions with delayed buildouts where renewable economics are less favorable in early periods.

5. POLICY RECOMMENDATIONS

This report presented pathways to carbon neutrality for China's power sector from 2020 to 2060. Table 2 highlights the deployment priorities by technology type across decades based on our simulation results. By examining the temporal deployment trends and localized impacts across regions, we identify policy recommendations in the near-term and long-term on both national and subnational levels, as shown in Table 3. Designing and implementing these policies requires greater coordination between the national and subnational governments, due to the need to address emerging local issues and ensure equity across regions. These policy efforts will not only consolidate China's leading role in the renewable energy sector, but can serve as a blueprint for other developing economies to transition away from fossil fuels.

Table 2 | Deployment Priorities Across Decades

<table>
<tr><th></th><th>Utility-scale solar</th><th>Distributed solar</th><th>Onshore wind</th><th>Offshore wind</th><th>Storage</th><th>Transmission lines</th></tr>
<tr><td>2020-2030</td><td colspan="2">Deploy in high-quality regions in the north and west</td><td rowspan="2">Deploy in northern regions and coastal regions</td><td rowspan="2">Ensure deployment efforts are sufficient in driving down costs in spite of unfavorable economics</td><td>Deploy in high-variable renewable energy regions to manage diurnal variations</td><td>Expand three regional clusters (northwest, south, and north)</td></tr>
<tr><td>2030-2040</td><td colspan="2">Extend to major load centers driven by continuous renewable cost declines</td><td rowspan="3">Prioritize battery storage in regions with limited hydro resource availability while promoting further battery cost declines</td><td>Strengthen major north-south corridors through both central and eastern regions</td></tr>
<tr><td>2040-2050</td><td rowspan="2">Largely exploit the available land near major load centers and continue the expansion in northern and western regions due to increasing land use and coal phasedown</td><td rowspan="2">Prioritize coastal regions due to proximity to load centers driven by lower transmission and integration costs</td><td rowspan="2">Prioritize coal-rich regions in the north to coordinate with the phasedowns of coal plants</td><td rowspan="2">Ramp up deployment in coastal regions due to rapid cost declines</td><td rowspan="2">Expand both interprovincial networks and long-distance national networks to accommodate renewable integrations</td></tr>
<tr><td>2050-2060</td></tr>
</table>

Table 3 | Policy Recommendations		
	National Government	**Provincial Governments**
Near-term (2020-2035)	• Incorporate and enforce clear deployment targets or portfolio standards in the upcoming five-year plans for renewable energy • Integrate storage and transmissions into the renewable planning processes with specific deployment targets • Set standards for regional electricity markets to allow more efficient power trading and balancing	• Promote retail and wholesale market reforms (e.g., time-of-use pricing, spot market trading) to improve renewable project economics • Identify strategies to facilitate coal retirement and mitigate local financial and social impacts
Long-term (2035-2060)	• Provide national guidance on renewable siting and permitting processes • Develop proper compensation mechanisms mainly for flexible conventional resources, and ensure continuous cost declines of renewables via auctions	• Monitor global markets for wind and solar equipment to ensure a sufficient supply to meet deployment targets • Establish project pathways and regional standards on installing renewables on agricultural lands • Strengthen effective compensation mechanisms to facilitate the least-cost deployment options for distributed energy resources

5.1. Accelerated buildout and integrated planning processes

The national government should incorporate the deployment needs of renewables, storage, and transmission lines into policy and financing frameworks. China has set a target of deploying at least 1,200 GW of wind and solar by 2030.[36] Our results demonstrate that higher rates of deployment beyond 2030 will be necessary to meet carbon neutrality targets, with annual installations of wind and solar increasing from 70 GW per year in the first decade to 210-300 GW per year in the last decade across scenarios. These deployment targets should be reassessed and specified clearly in upcoming FYPs.

As the grid sees higher renewable penetration rates, storage and transmission lines need to become an integral part of the planning processes. Our results show that the rate of storage capacity additions increases from 105-173 GWh per year in the first period to 180-260 GWh in the last period, while the transmission network expands at rates of 13-16, 13-38, 18-24, and 5-35 GW per year over the next four decades. These balancing resources are essential to integrate the accelerated deployment of renewables by addressing inter-regional imbalances and temporal variations. Specifically, the national government should consider extending the planning horizon to align industry expectations, improve cost allocation methods, and reduce risks of project delays due to right-of-way acquisition and environmental permitting requirements. In the U.S., many utility companies use a 20-year timeframe for their integrated resource plans.[37,38] Likewise, some transmission providers use 20-year transmission planning horizons.[39,40] The Federal Energy Regulatory Commission (FERC) has proposed that all transmission providers shift to a 20-year planning process.[41] Although our study assumes sequential 10-year planning periods, it is within the scope of future work to evaluate the benefits of 20-year planning.

Furthermore, the national government should highlight the regional dimension of deploying

36 National Development and Reform Commission, 2021a
37 RAP, 2013
38 RAP, 2021
39 California ISO, 2022
40 SPP, 2019
41 FERC, 2022

distributed energy resources (DERs) in the FYPs, including rooftop solar, small-scale wind, and battery storage systems. Our results show that the deployment of distributed solar expands from the western and northern regions in the first decade to major load centers starting from the second decade, while onshore wind will be more evenly allocated in both northern regions and major load centers along the coast across all decades. Battery storage systems are mostly correlated with the deployment of wind and solar. Although the current FYP calls for active promotions of distributed wind and solar power generation, there is a lack of spatial resolution and regional prioritization in the policy framework. Further clarifications will be essential to local governments in anticipating the possible land use bottlenecks and setting up complementary policy support for distributed energy resources. Notably, as the temporal-spatial trends identified in this study are primarily driven by the assumptions on the techno-economic performance of renewable technologies and the availability of firm resources, more frequent analyses are needed to keep up with the evolving market conditions, technological advances, and policy changes.

5.2. Deployment limits and supply chain constraints

The national government should consider setting up and improving renewable portfolio standards (RPS) at the provincial level to sustain short-term deployment rates and ramp up deployment in the long term. Our results show that the historical buildout rates of wind, solar, and storage will need to have a two- to three-fold increase in the long term to reach the installed capacities identified in this study. In 2021, the National Development and Reform Commission (NDRC) and other departments jointly issued a circular on strengthening financial support, such as adjusting short-term repayment schedules and arranging loan extensions, to promote the renewable deployment.[42] To encourage the desired level of investment in the near term, our results further indicate that an RPS will be essential in driving down project costs by promoting market adoption, especially for technologies that currently still have high capital costs but play important roles in future power systems, such as distributed solar, offshore wind, and battery storage. Conversely, a lack of policy support could delay the deployment process, leading to cumulative pressure on later periods where there is greater pressure to meet targets.

On the supply side, our results indicate that manufacturing capacity will be sufficient for covering the required wind and solar buildout in the near term and long term. The two-fold scale-up of storage manufacturing capacity is likely to be plausible too in the long term, given that 90% of the current battery manufacturing capacity is allocated to the transportation sector. For the wind and solar sectors, the manufacturing policies of local governments, on top of the central government's innovation framework, have helped to establish the engineering capabilities required for industrial upgrading.[43] Therefore, continuing local and central government support is necessary. Furthermore, the global market should be closely monitored, as rising international demands, volatile political environments, and risks of supply chain disruptions can pose additional challenges to the deployment.

5.3. Land use impacts of renewable deployment

As land use impacts become more prominent in eastern provinces in later time periods, both national and local efforts are necessary to promote efficient usage of land resources and to maintain balance among various land uses. The past decade has seen more stringent land use policies for renewable deployment. In 2017, the National Energy Administration and two other departments jointly issued land use regulations restricting solar deployment on productive agricultural lands and banning the use of permanent basic agricultural lands for solar.[44] Another policy draft has been circulated for comments since 2022, which considers extending land use restrictions to all the arable and forest lands for solar deployment.[45] However, accurate descriptions of land use constraints tend to be insufficient in national and local land use plans, adding uncertainties to project development. Prior studies focused on the U.S. have shown that

42 National Development and Reform Commission, 2021b

43 Nahm, 2017

44 National Energy Administration, 2017

45 People's Daily, 2022

land availability is one of the most significant determinants of the location, technology choices, and costs of renewable energy deployment.[46] Given the large renewable energy requirements and high levels of competing land uses in the populous coastal areas in China, the national government should provide guidance on siting and permitting to streamline the processes and reduce the lead time for renewable projects.

Local governments, on the other hand, should establish project pathways and regional standards for multiple land uses. For example, onshore wind can be prioritized on less ecologically sensitive lands in the near term and extended to farmlands in the long term. Both utility-scale and distributed solar can be deployed on barren lands, while distributed solar can be further promoted in urban areas, such as rooftops and commercial sites, for more efficient uses.[47] As the 14th FYP highlighted the development of distributed generation on agricultural lands across regions, the formation of detailed provincial standards can reduce project uncertainties and streamline the land use permitting process. Transmission lines can help alleviate the stress on land use, but require the formation of flexible regional electricity markets to allow more efficient trading between less land-constraint regions and major demand centers on the east.

5.4. Political economy of transmission expansion and coal retirement

There are likely two major political economy challenges facing the implementation of transmission expansion projects and coal retirement programs. First, as the inter-provincial transmission network continues to expand, local opposition could arise due to project siting[48] and inadequate cost allocation mechanisms.[49,50] Grid companies use volumetric and fixed transmission prices to recover the costs of transmission lines. These prices are predetermined by the NDRC and are primarily paid by the receiving provinces.[51,52] As the prices are inflexible and not always fair, the receiving end can see power purchase prices higher than those of local generators.[53] Therefore, the national government should require grid companies to move fully to cost-of-service based transmission remuneration mechanisms, such that they are not compensated based on how much each line is used. Furthermore, as there are existing policy efforts that provide accounting methods for transmission production costs,[54] the national government should adopt the beneficiary-pays principle (BPP) when it comes to cost allocation to generate buy-in from all relevant regions.

The second political economy challenge is related to coal retirement. As coal plants begin to retire in larger numbers, these can be associated with financial and social risks (e.g., stranded assets, job losses) without sufficient complementary policy support.[55] In most regions, our results demonstrate that the installed renewable capacity exceeds the retired coal capacity across decades, which can help diminish the macroeconomic effects of coal phasedown. Assuming that the renewable energy sector is more labor intensive than the coal sector, the potential job losses from coal retirement can also be offset by the gains from renewable buildout.[56] Supporting programs could therefore focus on capacity building and skill transfers, with emphasis on the renewable energy sector, where appropriate. However, our results show that several regions can have a misaligned coal retirement schedule if renewable deployment is concentrated in early or later periods. To make the transition more politically feasible, the national government should identify strategies tailored to local contexts such as equity-adjusted retirement schedules, and prioritize renewable deployment and more broadly transition assistance programs in impacted regions.

46 Wu et al., 2020
47 Wu et al., 2020
48 Lin & Xie, 2019
49 Guo et al., 2020
50 Li & Huang, 2020
51 National Development and Reform Commission, 2020a
52 National Development and Reform Commission, 2020b
53 NREL, 2021
54 National Development and Reform Commission, 2022
55 Cui et al., 2022
56 Zhou et al., 2022

5.5. Electricity market reforms

National and local governments should continue to conduct market reforms to ensure efficient and stable grid operations. On the retail side, the time-of-use tariff has encouraged the use of distributed energy resources for demand response and on-site generation.[57] Our results suggest that these resources will be integral to the future power system, especially in land-constrained coastal provinces. Therefore, local governments should update time-of-use tariffs to further promote the deployment of DERs and untap the system value that DERs can provide, while incorporating the need to reflect the changing system costs based on provincial and regional market conditions.

For wholesale electricity markets, power trading should extend from medium- and long-term markets to real-time spot markets, capacity markets, and ancillary services markets, as several provinces have begun to pilot.[58,59] Assuming that provinces and grid regions can trade power freely, our results suggest that the total trading volume will see a three-fold increase to 6.4 PWh in 2060. By contrast, the lack of efficient inner- and inter-regional trading mechanisms will waste more renewable generation while increasing overall system costs. Furthermore, one study that examined the recent rounds of Guangdong's spot market pilots has highlighted the challenges of spot market operations, such as market inefficiencies caused by price floors, and increased electricity rates due to market manipulation.[60] Considering these potential barriers to future liberalization endeavors, the national government should set and update standards for operating regional markets. In the long term, proper market mechanisms should be developed to allow flexible conventional resources to recover costs under high renewable penetrations.

[57] International Energy Agency, 2019

[58] Davidson & Pérez-Arriaga, 2020

[59] Guo et al., 2020

[60] Liu et al., 2022

6. CONCLUSION

Decarbonizing the power sector is essential to achieving China's ambitious climate policy targets of reaching peak carbon emissions by 2030 and neutrality by 2060. This process entails an unprecedented pace of deployment of renewable energy, storage systems, and transmission lines across periods and regions. Examining the structures and pace of this transition, results show that annual combined installations of wind and solar increase from around 70 GW per year in the first decade (2020-2030) to 210-300 GW per year in the last decade (2050-2060). Integrating these variable energy resources into the grid requires storage and transmission lines to address inter-regional imbalances and inter-temporal variations: annual storage additions increase from 105-173 GWh per year in the first decade to 180-260 GWh per year in the last decade, and the transmission network expands at rates of 13-16, 13-38, 18-24, and 5-35 GW per year across four decades. By contrast, historical rates of manufacturing capabilities are likely to be sufficient, depending on exports of clean energy technologies. Based on these findings, the national government should coordinate the development of renewables, storage, and transmission, and set clear deployment targets in the five-year plans.

The second question that we examined is about the geographical distributions of different technologies over time. Our results show that utility-scale and distributed solar will expand from the north and west to major demand centers starting from the second period, while distributed solar will have stronger prominence in regions along the coast in later periods despite having lower CFs, due to lower transmission and integration costs of locating close to demand centers. In addition, onshore wind has a large footprint both in the north and along the coast, while continuous cost declines will promote the deployment of offshore wind in coastal provinces. Relatively high transmission costs drive renewable deployment in lower-quality regions, but low-cost storage alters this dynamic by allowing renewable deployment in high-quality regions in later periods facing higher integration costs. These findings suggest that regional prioritizations and renewable portfolio standards at the provincial level will be valuable for guiding local governments and sustaining the current momentum of deployment.

Lastly, we examined the potential impacts on land uses, among other political economy and electricity market challenges. Based on the study findings, solar deployment will exhaust the majority (51-82%) of suitable land in eastern provinces by 2060, while wind will impact provinces along the coast the most (14-48%), driven by renewable potentials and installed capacities. While further guidance on siting and permitting from the national government is needed, local counterparts should establish project pathways and regional standards for co-location uses to deescalate project uncertainties and mitigate land use impacts. Furthermore, as the transmission network becomes more interconnected, the total trading volume will likely see a 3-fold increase by 2060. Efficient inner- and inter-regional trading mechanisms are essential in promoting renewable integration and reducing system costs.

Although this study explores the feasible and efficient sequential pathways to achieving carbon neutrality for China's power sector, the structure, pace, and distributional impacts can be further affected by a myriad of uncertain factors such as demand growth, capital costs, inter-annual renewable variations, and technology choices. Obtaining pathways under all permutations of these factors would be computationally intractable and conceptually cumbersome, but future work could examine the effects of individual variables depending on the context of the research questions. When designing and implementing renewable policy programs, policymakers should take a technology-agnostic approach and continue to invest in early-stage technologies that are not commercially available yet. Another limitation of this study lies in the scope of the simulation task—the capacities of firm resources are not co-optimized as outputs, while heating demand is assumed to be met across periods. The implication for policymakers is that the transition of China's power sector requires more detailed supporting policies during the implementation process.

Overall, our novel modeling approach is useful in examining the changes in power system structures over time, renewable deployment paces, and economic and social impacts related to deployment that vary by regions. From a policy-making perspective, this information helps national and subnational governments plan, anticipate bottlenecks and address potential challenges. Furthermore, our analysis helps support a more effective, efficient, and equitable clean energy transition in China.

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8. APPENDIX

A. Model formulation

We develop a high-resolution power system planning and operation model to simulate China's power sector in each decade. The model optimizes the amount and location of variable renewable energy (VRE), storage systems, and transmission lines at the lowest cost, while satisfying provincial hourly electricity demands, grid reliability, and land use constraints, among other requirements, for a whole year of operation.[61]

The objective of each simulation is to minimize the total annualized costs of investment and generation dispatch. Specifically, these costs include the generation and connection costs of VRE, the capital costs of building new inter-provincial transmission lines, the capital and operational costs of deploying storage systems, the generation and ramping costs of firm resources, and the costs of meeting reserve requirements.

Each model run includes exogenous parameters obtained from relevant modeling studies and policy documents as input. These parameters can be classified into two main categories: fixed parameters (e.g., technical and policy parameters), and time-varying parameters (e.g., electricity demand, firm resource capacities, and costs). Detailed input assumptions are covered in the following sections.

Each simulation requires a set of planning and operation constraints to satisfy. First, the supply of electricity at each hour has to be equal to the demand at the provincial level. Then, the hourly VRE power output should be less than or equal to the maximum generation capacity at the provincial level, and each grid cell's installed capacity should be greater than or equal to the existing capacity in each decade. Furthermore, firm resource power output should be less than or equal to the maximum firm resource capacity on a provincial level. We also consider the transmission line capacity and storage operation constraints. Lastly, we incorporate two reserve requirements (i.e., demand reserve and VRE integration reserve) at the grid region level to ensure grid reliability. The demand reserve requirement is that the total available capacity, including all the generation resources and storage systems, has to exceed the hourly demand by a certain margin, and the VRE integration reserve requirement is that the firm resource capacity has to exceed the total VRE capacity by another margin. Across decades, notably, we impose a deployment constraint where VRE, transmission, and storage capacities in each decade have to be greater than or equal to those of the last decade. This constraint leads to a more realistic buildout roadmap and ensures contingency in model outcomes.

B. Technical parameters for firm resources

To improve the computational tractability of our simulation model, we adopt the concept of generation "layers", where optimal dispatch decisions are determined based on a heuristic ordering of various generation types.[62] Table A1 presents the types of generators at each generation layer. The baseload layer (L1) includes generators that have a must-run limit. Specifically, the must-run ratios are 80% for BECCS, 85% for nuclear, and 100% for coal CHP CCS during wintertime.[63]

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[61] Zhang et al., Under Review

[62] Davidson et al., 2016

[63] Zhang et al., Under Review

Table A1 | Generation Layers and Generator Types	
Generation layer	**Generation types**
L1	BECCS, nuclear, and coal CHP CCS (wintertime)
L2	Hydro
L3	Remainder of nuclear
L4	Unabated coal, coal CCS, and remainder of coal CHP CCS
L5	Unabated gas, and gas CCS

We assume that the ramp rates are 25% for hydro (L2), 5% for nuclear (L3), 25% for coal (L4), and 50% for gas (L5).[64,65,66] The ramp-up costs are 0 for hydro (L2), 0.2 RMB/kWh for nuclear (L3), 0.05 RMB/kWh for coal (L4), and 0.01 RMB/kWh for gas (L5), while the ramp-down costs are 0 for all layers.[67] We also consider a 5% demand reserve and VRE integration reserve requirement.[68,69] The reserve costs are 0 for hydro (L2), 0.025 RMB/kWh for nuclear (L3), 0.024 RMB/kWh for coal (L4), and 0.026 RMB/kWh for gas (L5).[70] Furthermore, power plants that are retrofitted with CCS equipment have a 5% power loss.[71]

C. Technical parameters for storage and transmissions

Two types of storage technologies are considered in this study: pumped hydro storage (8-hour duration) and battery storage (4-hour duration). Table A2 shows the technical parameters for storage technologies across decades. China's National Energy Administration (NEA) has set deployment targets for pumped hydro storage from 2021 to 2035 and identified long-term deployment potential across provinces, totaling 726 GW across the nation.[72] We incorporate the details of this plan as the constraints for our simulations. Specifically, we use the installed capacity and capacity under construction as the minimum capacity for pumped hydro storage capacity at each province from 2030 to 2060. Additionally, we use the long-term deployment potential as the maximum capacity from 2030 to 2060.

Three types of transmission lines are considered in this study: spur lines, trunk lines, and inter-provincial lines to facilitate the integration of renewable energy into the grid. Spur lines are used to connect cells to substations, and trunk lines are used to further connect substations to the nearest major grid nodes in the province. We assume 220 kV alternating current (AC) spur and trunk lines will be used. For inter-provincial transmission lines, we assume that the expansion is only applicable to the existing network. In other words, if two provinces do not have existing links as of 2020, no new lines will be built. New inter-provincial transmission lines have a voltage level of 1000, 800, 750, and 500 kV. For all the transmission line types, transmission losses are assumed to be 0.0032% per km.[73]

Table A2 | Energy Storage Technical Parameters			
Storage technology	**Duration (hrs)**	**Round-trip efficiency (%)**	**Lifespan (yrs)**
Pumped hydro	8	78%	40
Battery	4	95%	15

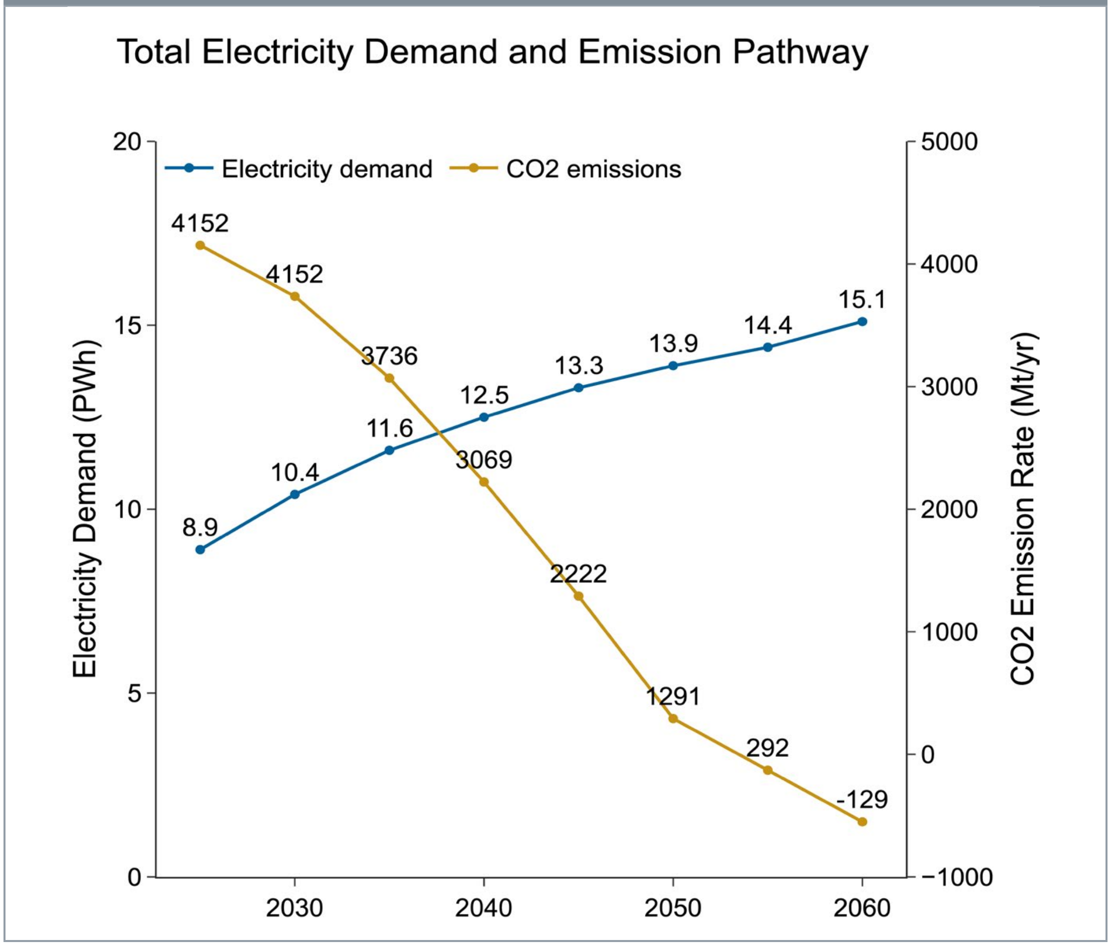
64 Brown & Botterud, 2021
65 Chen et al., 2021
66 Zhang et al., Under Review
67 Zhang et al., Under Review
68 Davidson et al., 2016
69 Zhang et al., Under Review
70 Zhang et al., Under Review
71 Asian Development Bank, 2022
72 National Energy Administration, 2021
73 Liu et al., 2015

D. Total electricity demand and power sector emissions

Figure A1 shows China's power sector's electricity demand and emission pathway from 2020 to 2060. We assume national and provincial demand increases at declining rates across decades, reaching 15.1 PWh by 2060.[74] Based on the projections of total national demand in each year, we calculate percentage increases relative to that in 2020 and apply the scaling factor to provincial hourly demand profiles in 2020 to obtain each year's provincial demands.[75]

We set boundary conditions of the power sector to have a carbon emission trajectory consistent with a 2ºC global average temperature rise target,[76] and further let power become a net emission sink with 550 million tons of negative carbon emissions in 2060 to offset emissions from other sectors.

Figure A1 | Total Electricity Demand and Emission Pathway for China's Power Sector



E. Capacity assumptions for firm resources

We obtain firm resource capacities from other modeling studies and use them as the exogenous input for our simulations. Figure A2 shows the total national firm resource capacities from 2020 to 2060. Across scenarios, we assume that total hydro and nuclear capacities would reach 580 and 218 GW by 2060, respectively.[77,78] On a provincial level, we first adopt the hydro installation projections by each region for 2025, 2030, 2050, and 2060 based on the GEIDCO report, and linearly interpolate the missing value for 2040. Then we calculate the percentage increases in regional hydro capacities each

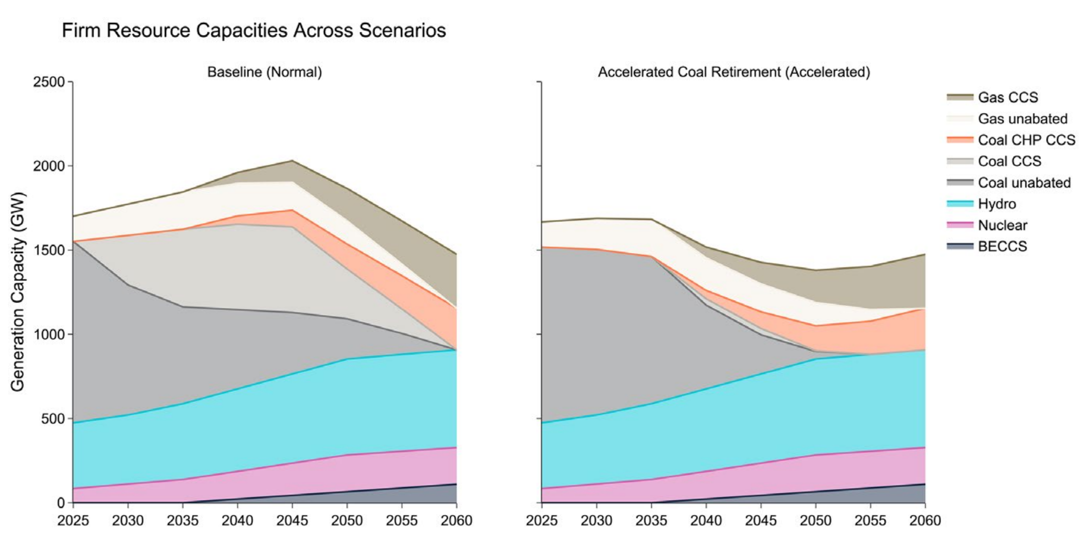
74 Zhang et al., 2022
75 Davidson et al., 2016
76 Tsinghua University, 2020
77 Global Energy Interconnection Development and Cooperation Organization, 2021
78 Xiao & Jiang, 2018

year relative to the 2020 level and apply those to provincial hydro capacities in 2020 for each province within the region.[79,80] For nuclear, we adopt the total capacity projections with provincial breakdowns in 2050 from one study and linearly interpolate the missing values in between. Additionally, we assume the capacity remains fixed from 2050 to 2060 to be consistent with the study findings.

Negative emissions of the power sector will be achieved by the deployment of bioenergy with carbon capture and storage (BECCS). We assume that BECCS enters the market in 2040 and reaches 110 GW by 2060, while linearly interpolating the capacity values in between. BECCS has a capacity factor of 0.8, a carbon intensity of -1 kgCO2/kWh, and an 88% capture rate.[81] Furthermore, each year's projected BECCS capacity is distributed to major source regions abundant in forest resources and sink regions suitable for carbon sequestration projects, including Sichuan Basin, Jianghan oil field, Bohai Bay Basin, Guangxi, Yunnan, and Songliao Basin.[82]

Gas plants will be retrofitted with carbon capture and storage (CCS) equipment from 2040, reaching 320 GW of gas CCS capacity in 2060, while unabated gas will completely phase out by 2060. We adopt GEIDCO's projections of total national gas capacity for 2025, 2030, 2050, and 2060, and linearly interpolate the missing capacity values in between.[83] For gas CCS, we assume linear increases from 0 GW starting from 2040, and then subtract gas CCS capacity from the total gas amount to calculate the capacity of unabated gas. Furthermore, we multiply these values by each province's percentage share in 2018 to obtain provincial breakdowns.[84]

Figure A2 | Total National Firm Resource Capacities from 2020 to 2060



F. Coal retirement and retrofit

Coal plant CCS retrofits and retirements are determined via a plant-by-plant strategy to ensure compliance with carbon emission targets. Specifically, we prioritize CCS retrofit decisions of individual plants based on the total emissions of their remaining lifetime. Plant-level data are obtained from Global Energy Monitor.[85] At each retrofit year, the largest and most polluting coal plants will be retrofitted until we reach the emission targets when taking into consideration other carbon sources and sinks. Through this mechanism, we can track the retrofits and retirements at each decade on a provincial level.

79 China Electricity Council, 2021
80 National Energy Administration, 2021
81 Lu et al., 2019
82 Wei et al., 2021
83 Global Energy Interconnection Development and Cooperation Organization, 2021
84 China Electricity Council, 2021
85 Global Energy Monitor, 2022

In the Baseline Scenario, coal plants have a lifespan of 40 years, while those that have at least 25 years of planning lifetime left as of 2020 with a capacity greater than 400 MW would be eligible for retrofits starting from 2030. By comparison, in the Accelerated Coal Retirement Scenario, we assume that more stringent policy frameworks will be implemented to facilitate the retirement of old, small, and polluting coal plants.[86] Coal plants are expected to have 30 years of lifespan, while coal retrofitting only starts after 2040, given that a shorter lifespan accelerates retirement and reduces the need for retrofit to meet emission targets for the power sector.

Considering China has a massive existing central heating network in North China, we assume coal combined heat and power (CHP) capacity will not retire by 2060, but rather, be retrofitted with CCS starting from 2040 to meet North China's district heating demand during wintertime. Total coal CHP CCS capacity will reach 248 GW by 2060.[87] Furthermore, we assume linear increases in coal CHP CCS capacity from 2040 to 2060. This approach does not incorporate the coal CHP capacity in the GEM dataset, in that it is not possible to separate coal CHP plants from the rest of the dataset due to a lack of plant-level information regarding plant types and uses.

Major carbon sources of the power sector include unabated coal, coal CCS, coal CHP CCS, unabated gas, and gas CCS, while BECCS offsets the positive emissions from the other technologies. As described above, the amount of coal CHP CCS, unabated gas, gas CCS, and BECCS are obtained first. Then we implement the plant-by-plant coal retirement and retrofit strategy to calculate the provincial breakdowns of unabated coal and coal CCS capacities. In this process, we assume an 88% partial capture rate for all the CCS equipment, a capacity factor of 10% for gas plants and 30% for coal CHP CCS, and a carbon intensity of 0.5 kgCO_2/kWh for gas plants and 1 kg CO_2/kWh for coal CHP CCS.[88,89] Eventually, we are able to obtain the capacity values for all the firm resources and use them as exogenous input for the simulations.

Table A3 | Renewable Generation Costs in 2020 and 2060

Renewable technology	2020		2060	
	Capex (RMB/kW)	O&M cost (RMB/kW-yr)	Capex (RMB/kW)	O&M cost (RMB/kW-yr)
Onshore wind	7700	170	3000	45
Offshore wind	15000	715	5400	81
Utility-scale solar	5300	85	1500	7.5
Distributed solar	5300	107	2000	10

Table A4 | Energy Storage Costs in 2020 and 2060

Storage technology	2020			2060		
	Capex (RMB/kW)	Fixed O&M cost (RMB/kW-yr)	Variable O&M cost (RMB/kWh)	Capex (RMB/kW)	Fixed O&M cost (RMB/kW-yr)	Variable O&M cost (RMB/kWh)
Pumped hydro (8-hour)	3840	4.5	0.0015	3840	39	0.0015
Battery (4-hour)	6000	25	0.025	2700	18	0.02

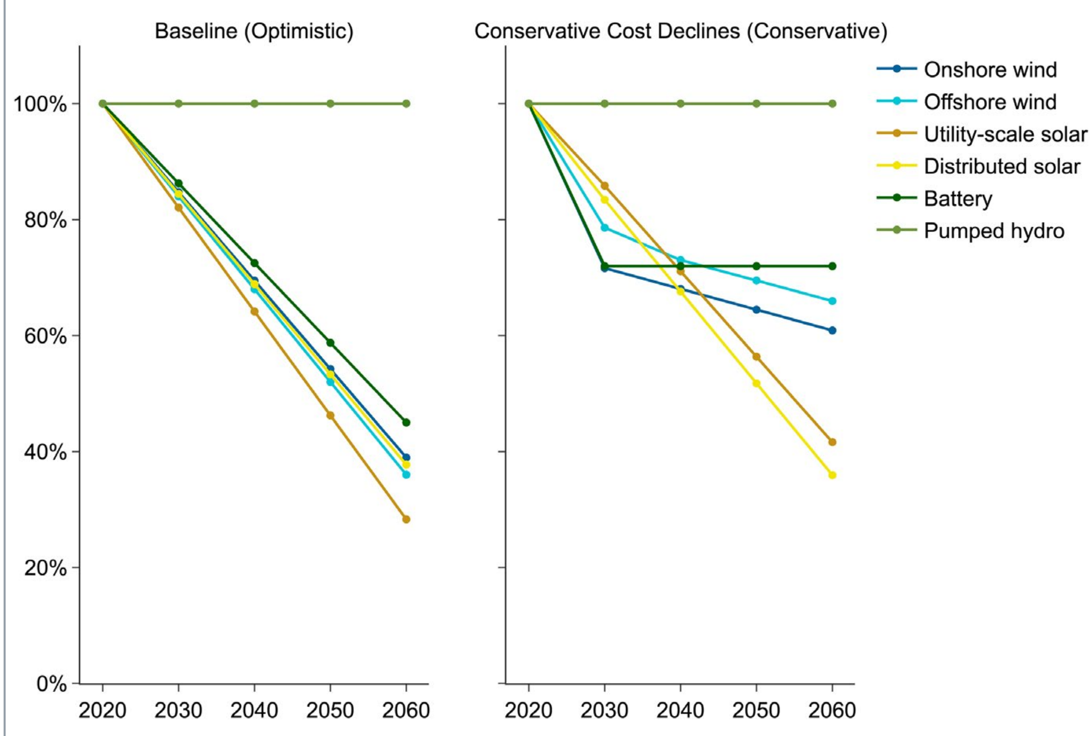
86 Cui et al., 2022
87 Zhang et al., Under Review
88 Asian Development Bank, 2022
89 Energy Information Administration, 2022

G. Cost assumptions for renewables, storage, and transmissions

Table A3 and A4 show the cost assumptions in the Baseline Scenario for renewables and energy storage technologies, respectively. We linearly interpolate the cost values for the years between 2020 and 2060. By comparison, in the Conservative Cost Declines Scenario, we assume that the capital costs of wind, solar, and storage have fewer percentage decreases than the baseline, based on technology-specific projections of the conservative category from the U.S. National Renewable Energy Laboratory.[90] We did not directly use the renewable capital costs in NREL's study due to the consideration of market differences. Instead, we used the same cost values as the starting point in 2020 for both scenarios, but apply different percentage decreases to each scenario. In this way, we can understand how prices impact renewable deployment. Figure A3 presents the comparison in percentage decreases of capital costs of various technologies across scenarios.

We assume that all the scenarios have the same transmission line costs. The fixed costs are 262 and 159 RMB/kW across decades for spur lines and trunk lines, respectively, while the variable costs are 3 and 1.76 RMB/kW-km for spur lines and trunk lines.[91] On a national level, we consider the expansion of the inter-provincial transmission network to facilitate regional electricity transfers. The capital costs of building inter-provincial transmission lines vary with the existing linkage's voltage level. For lines with a voltage level of 1000, 800, 750, and 500 kV, we assume that the substation costs are 370, 592, 148, and 159 RMB/kW, respectively, while the overhead line costs are 7.08, 4.95, 2.99, and 2.64 RMB/km, respectively.[92]

Figure A3 | Percentage Decreases of Capital Costs of Various Technologies from 2020 to 2060



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90 NREL, 2021

91 Zhang et al., Under Review

92 Zhang et al., Under Review

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