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Authors:

Gang He[1,2,*], Jiang Lin[2,3,*], Froylan Sifuentes[2], Xu Liu[2], Nikit Abhyankar[2], and Amol Phadke[2,*]

[1] **Stony Brook University**
Department of Technology and Society
College of Engineering and Applied Sciences

[2] **Lawrence Berkeley National Laboratory**
Energy Analysis and Environmental Impacts Division
International Energy Analysis Department

[3] **University of California, Berkeley**
Department of Agricultural and Resources Economics

* Corresponding authors: gang.he@stonybrook.edu ; j_lin@lbl.gov; aaphadke@lbl.gov

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Abstract

China's power sector is key to achieving decarbonization targets for China and the rest of the world. The costs for solar photovoltaics, wind, and battery storage have dropped markedly, approximately 65% to 85% since 2010. Those costs are projected to decline further in the near future, bringing new prospects for the widespread penetration of renewables and extensive power-sector decarbonization that previous policy discussions did not foresee. The results of our study show that if cost trends for renewables continue, 62% of China's electricity will come from non-fossil sources by 2030 at a cost that is 11% lower than achieved through a business-as-usual approach. Further, China's power sector can cut half of its 2015 carbon emissions at a cost about 6% lower compared to business-as-usual conditions. An 80% reduction in 2015 carbon emissions is technically feasible as early as 2030, but requires about a 21% higher cost than the business-as-usual approach, for a \$21/tCO_2 cost of conserved carbon.

Introduction

China's electricity system accounts for about 45% of the country's energy-related carbon dioxide (CO_2) emissions, which represent about 13% of total global energy-related CO_2 emissions.[1] Decarbonizing China's electrical system therefore is essential to the decarbonization of energy systems not only in China but also globally. Further, given electricity's increasing role in China's energy use, a low-carbon electrical system is key to reducing CO_2 emissions from other economic sectors such as transport, industry, and buildings.

Under the Paris Agreement, China committed to peak its CO_2 emissions and to supply 20% of its energy demand using non-fossil sources by 2030. Such targets, however, are unlikely to limit the worldwide temperature increase to 2 or 1.5 degrees above pre-industrial levels.[2] Various studies have outlined strategies for China to attain a high degree of non-emitting generation by 2050.[3–6] Many recent studies and reports around the world have not adequately captured the dramatic decrease in costs of renewable energy and storage, however. For example, the World Energy Outlook produced by the International Energy Agency and the International Energy Outlook developed by the U.S. Energy Information Administration have under-estimated the development of renewables.[7–9]

Incorporating the new downward trend in costs of renewable energy into models of the power sector is both relevant to modeling efforts and required for developing appropriate policies. The analysis described herein aims to incorporate recent trends in renewable and storage costs so as to explore more ambitious pathways to decarbonizing China's power system by about 2030 and to offer insights on how those recent trends can reshape the power system. The costs of solar photovoltaics (PV), wind, and battery storage have decreased rapidly approximately 50% to 85% since 2010 and are projected to decrease further in the near future.[10–12] Those cost trends bring new possibilities for widespread penetration of renewable energy sources and comprehensive power-sector decarbonization that were not foreseen in previous policy discussions.

We focus on the following questions in this study: how would China's power system change given the rapid decrease in costs of renewables and more stringent CO_2 emissions targets? What are the costs to achieve those changes in China's power system? How would those changes affect China's regional pattern of power development and transmission? By addressing those questions, this paper is the first effort to reveal the implications of cost decrease on power systems and new perspectives on clean power transition that are not visioned in the exitsting literature.

We updated the SWITCH-China model[13] and developed four scenarios for 2030 to simulate and understand the effects of the rapid decrease in renewable energy costs. The scenarios are: 1) business as usual scenario (BAU), which assumes the continuation of current policies and moderate cost decreases in future renewable costs; 2) Low-cost renewables scenario (R), which assumes the rapid decrease in costs for renewables and storage will continue; 3) Carbon constraints scenario (C50), which has a carbon cap of 50% lower than the 2015 level in 2030 on top of the R scenario; and 4) Deep carbon constraints scenario (C80), which further constrain the carbon emissinos from the power sector to be 80% lower than the 2015 level by 2030. Table 1 summarizes the key assumptions of the four scenarios.

Table 1. Model Scenarios

	Business as usual (BAU)	Low-cost renewables (R)	Carbon constraints (C50)	Deep carbon constraints (C80)
Base year	Base year: 2015			
Existing Policies	Continuation of current policies and no new coal plants after 2020 because of tight regulations on air pollution and institution of carbon mitigation measures[14]			
Future Renewable Costs Assumpsions	Utilizing conventional models for future renewable costs	Rapid decrease in costs for renewables and storage continues: dramatic decreases in wind, solar, and storage costs as projected by Lawrence Berkeley National Laboratory (LBNL) and the National Renewable Energy Laboratory (NREL)		
Carbon constraints	No	No	50% reduction in power sector CO_2 from 2015 level by 2030	80% reduction in power sector CO_2 from 2015 level by 2030

Mix of generation capacities and power generation

As expected, rapid decreases in the costs of renewable energy sources lead to the larger installation of wind and solar capacity. By 2030, the low-cost renewables (R) scenario, compared with the BAU scenario, would lead to an increase in wind capacity from 660 to 850 GW and in solar capacity from 350 to 1,260 GW. The need for power sector generators to incorporate flexibility in utilizing resources would result in increasing storage capacity from 34 to 290 GW to support the integration of variable renewable resources. The need for natural gas capacity would decrease from 300 to 170 GW, replaced by increasing renewable capcities and storage cpacities. Coal capacity would diminish from 750 to 700 GW (Figure 1), about a 7% reduction.

Under the carbon constraints (C50) scenario, coal capacity would decrease further to 520 GW by 2030, almost a 1/3 reduction compared with the BAU scenario. The deep carbon constraints (C80) scenario would phase out coal further to about 200 GW, only 4% of total capacity. The decrease in coal use would be offset primarily by renewables: 1,920 GW of solar and 2,000 GW of wind.

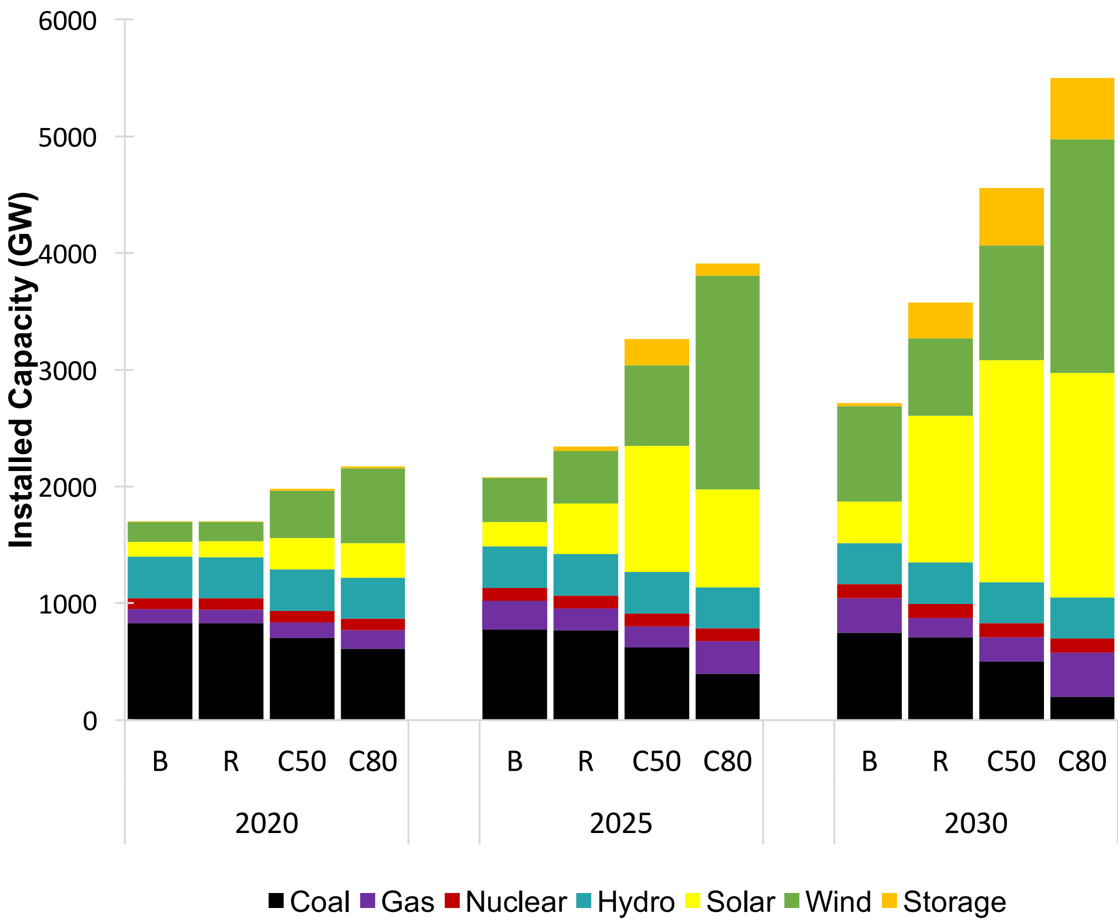


Figure 1 Capacity mix for four scenarios in 2020, 2025, and 2030

Under R scenario, coal-based generation would decrease from 4,900 TWh in the BAU scenario to 3,700 TWh by 2030, a 30% reduction. Wind and solar production would provide

39% of electricity need, with battery storage and natural gas supplementing the increasing wind and solar supplies. The total share of non-fossil generation would reach 62% in 2030. The C50 scenario would cause coal generation to decline further to 2,400 TWh (less than half the amount generated under the BAU scenario), while the share of non-fossil generation would increase to 77% in 2030. The C80 scenario would reduce coal generation to about 960 TWh, or to about 10% of total power generation, while the share of non-fossil generation would approach 90% in 2030 (Figure 2).

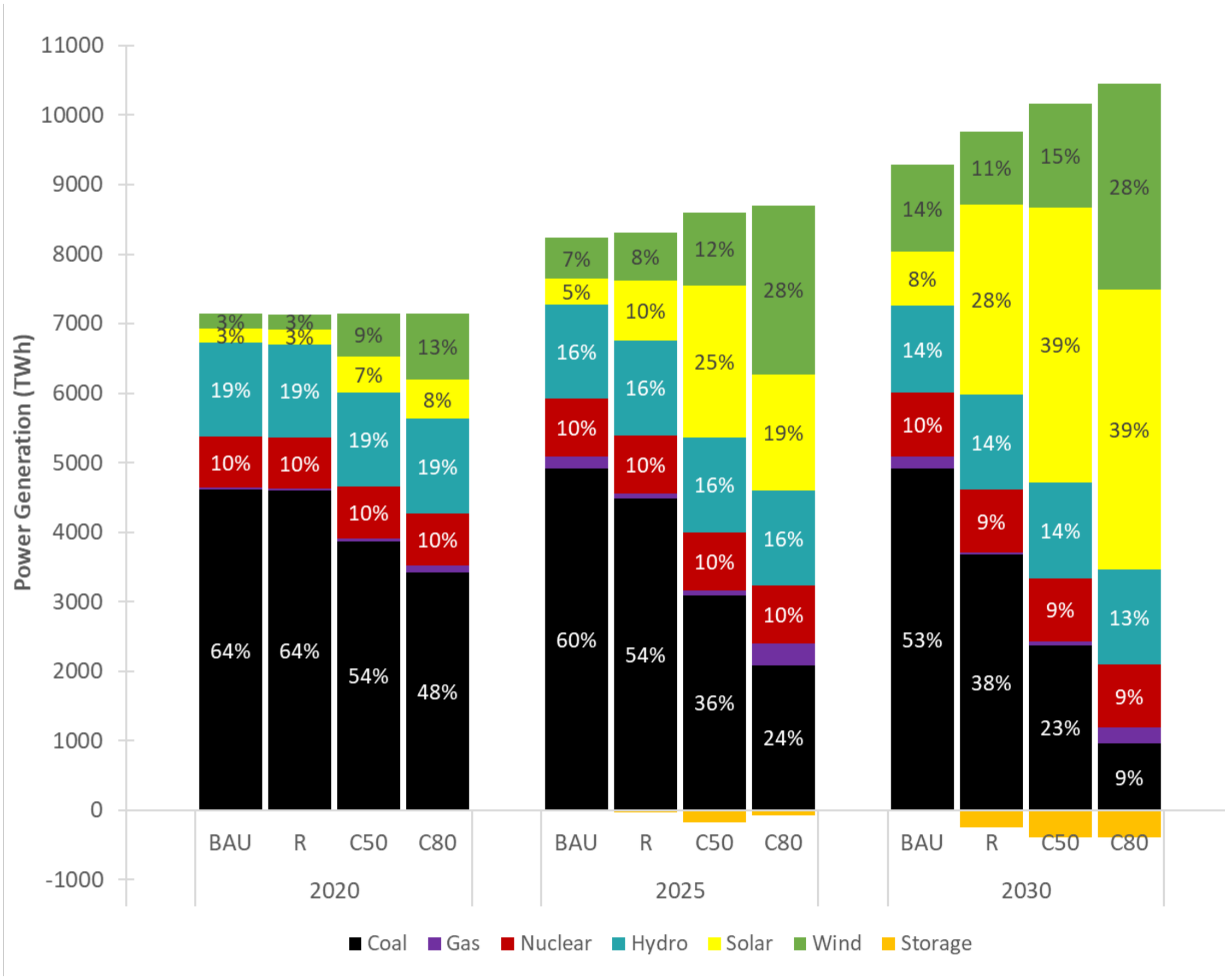


Figure 2 Mix of power-generating resources for four scenarios in 2020, 2025, and 2030

Relying on variable wind and solar resources for electricity would pose challenges to system operations. On days with abundant wind and solar resources, upto 300 GW of storage would be needed to balance the power system under the R scenario. On days that provide minimal solar and wind power, storage would be inadequate to make up for the shortage; natural gas generation would fill the gap in order to satisfy peak load requirements. Figure 3 shows that dispatch sources to meet demands would be operationally manageable with the addition of electricity from battery storage and natural gas.

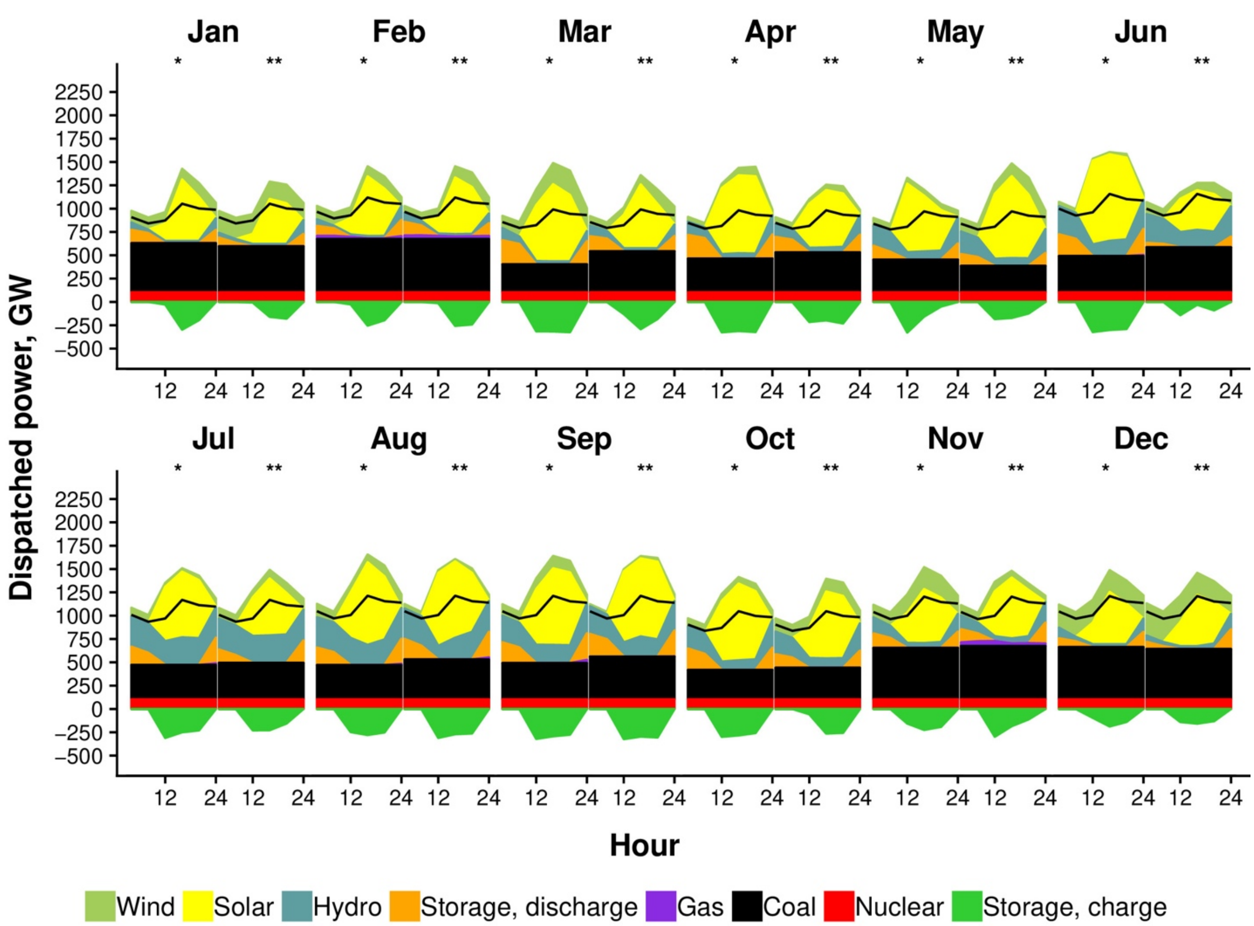


Figure 3 Hourly dispatch sources in 2030 for a normal day (•) and a special day (••) each month under the R scenario

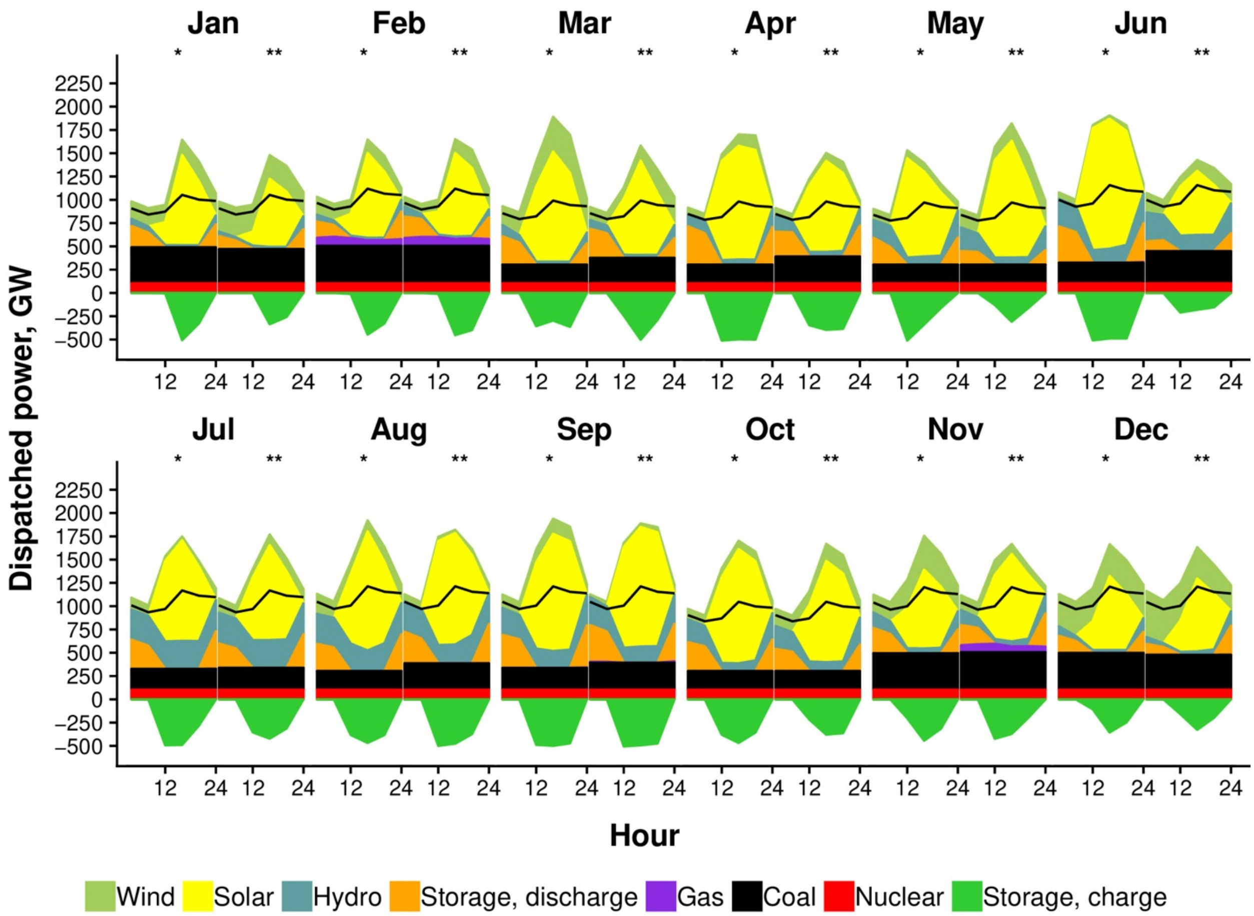
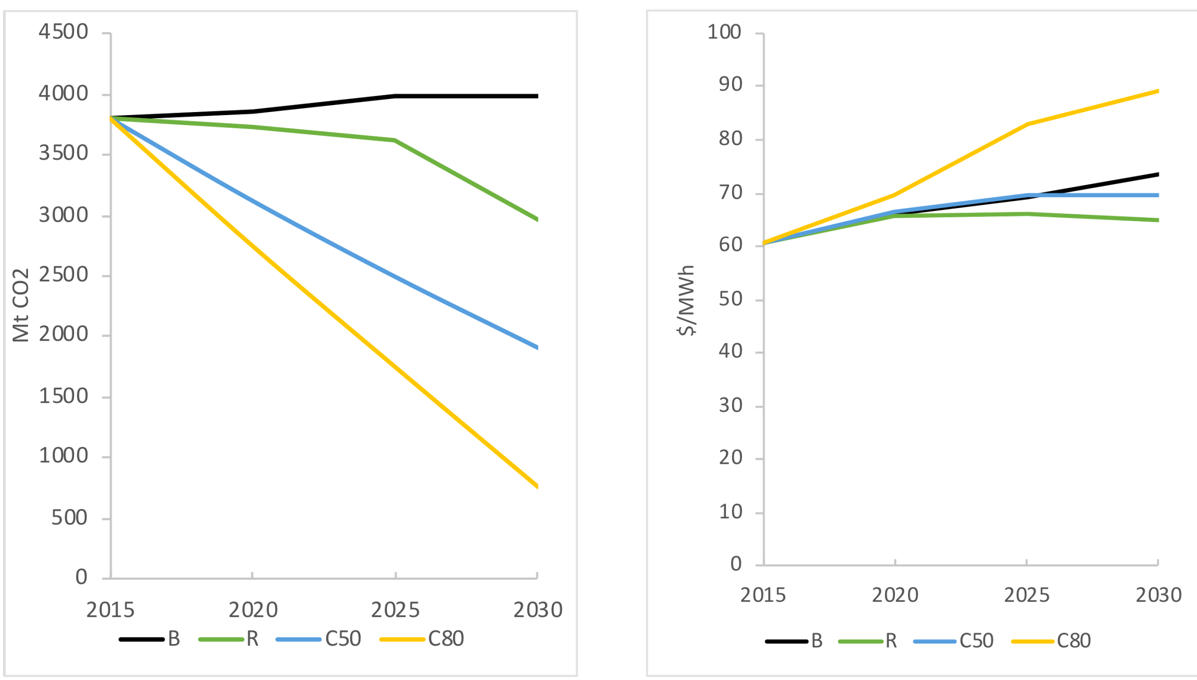


Figure 4 Hourly dispatch sources in 2030 on a normal day (•) and a special day (••) in each month under the C50 scenario

Power costs and carbon emissions

A low-cost renewables (R) scenario would reduce carbon emissions significantly, from 3, 980 $MtCO_2$ under the BAU scenario (5% above the 2015 level) to 2,970 $MtCO_2$ by 2030 (22% below the 2015 level), see Figure 5(a). Given the remarkable and ongoing reductions in the cost of renewable power, this 30% reduction in carbon emissions could be achieved for a lower cost of power under the R scenario than under the BAU scenario, see Figure 5(b). Power costs would decrease from 73.52 \$/MWh under the BAU scenario to 65.08 \$/MWh under the R scenario, an

11% reduction. Under the carbon constraint (C50) scenario, carbon emissions in 2030 would be half of those of 2015, on a trajectory to achieve an 80% reduction by 2050. The cost of power under the C50 scenario is calculated to be 69.47 \$/MWh, only 7% higher than under the R scenario, and but still 6% lower than under the BAU. In the deep carbon constraint (C80) scenario, the cost of power would increase to 89.08 \$/MWh, and 21% higher than under the BAU scenario. The cost of conserved CO_2 would be -\$36/tCO_2, -\$9/tCO_2, and \$21/tCO_2 under the R scenario, C50 scenario, and C80 scenario, respectively. China has already initiated a national cap-and-trade program limiting the carbon emissions from the power sector with a carbon price ranging from 20 RMB/tCO_2 (\$3/tCO_2) to 100 RMB/tCO_2 (\$14.5/tCO_2).



5(a) Carbon emissions under four scenarios 5(b) Power costs under four scenarios

Figure 5 Carbon emissions and power costs to 2030 under four scenarios

Changing Investment Mix

A low-cost renewables (R) scenario would shift the cost structure of the power system from a fuel intensive system to a more capital investment driven system, see Figure 6. The fuel cost of coal plants would decrease from about $100 billion in the BAU scenario to about $65 billion in the R scenario. New capital investment of solar, wind, and storage capacity in the R scenario is only slightly higher than the BAU scenario contribute to the lower cost of renewables and storage, from $55 billion in the BAU scenario to about $65 billion in the R scenario. The overall power system cost in the R scenario is $280 billion, 11% lower than that in the BAU scenario, $310 billion. Total costs under C50 and C80 are $285 billion and $390 billion, respectively in 2030.

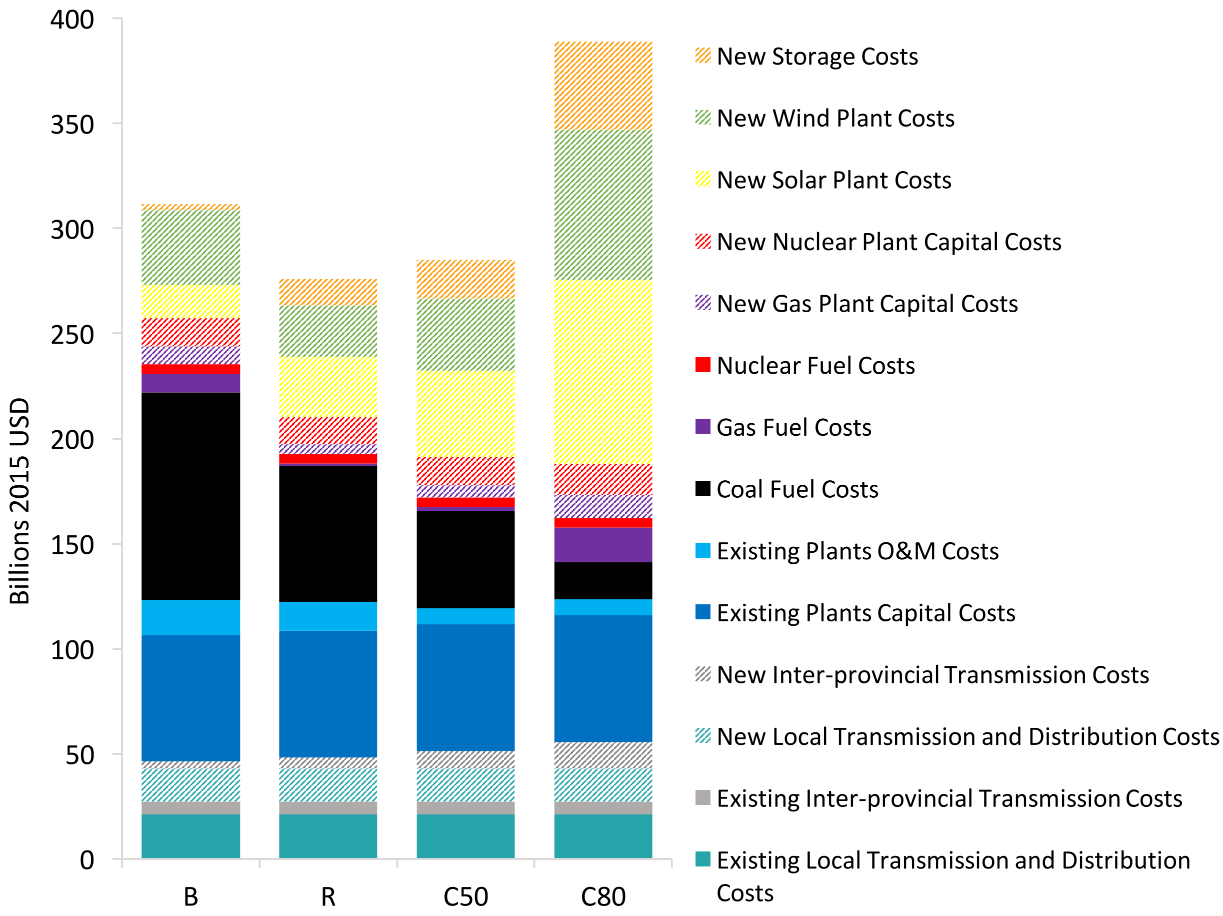


Figure 6 Distribution and costs of power sources under four scenarios to 2030

Regional disparities and needs

Mapping the mix of resource capacity and required new transmission under the R scenario reveals regional disparities in the development of renewable energy sources (Figure 7). First, solar capacities are concentrated in the northwest—in the provinces of Inner Mongolia, Qinghai and Shaanxi. Each of those areas has more than 100 GW of solar capacity. Wind capacities are more evenly distributed along the northwest, northeast, and eastern coastal provinces. Xinjiang, Heilongjiang, Shaanxi, Guangxi, Jilin, and Shanxi provinces have the greatest number of wind installations; each has more than 30 GW of wind capacity. Bringing the power generated from renewable sources to the areas of demand requires extensive transmission infrastructure. The focus for new transmission capacities are the three metropolitan areas of Jing-Jin-Ji, the Yangtze Delta, and the Pearl River Delta. New transmission infrastructure is needed to bring wind and solar energy from the northwest (Qinghai, Gansu, Inner Mongolia, and Shaanxi) to the central and eastern China grids; for example, from Inner Mongolia to Hebei, Beijing, and Tianjin; from Yunnan to Guangxi and Guangdong; from Anhui and Jiangsu to Zhejiang and Shanghai. The necessary transmission capacity could be as great as 35 GW, which would double the current maximum cross-provincial transmission capacity.

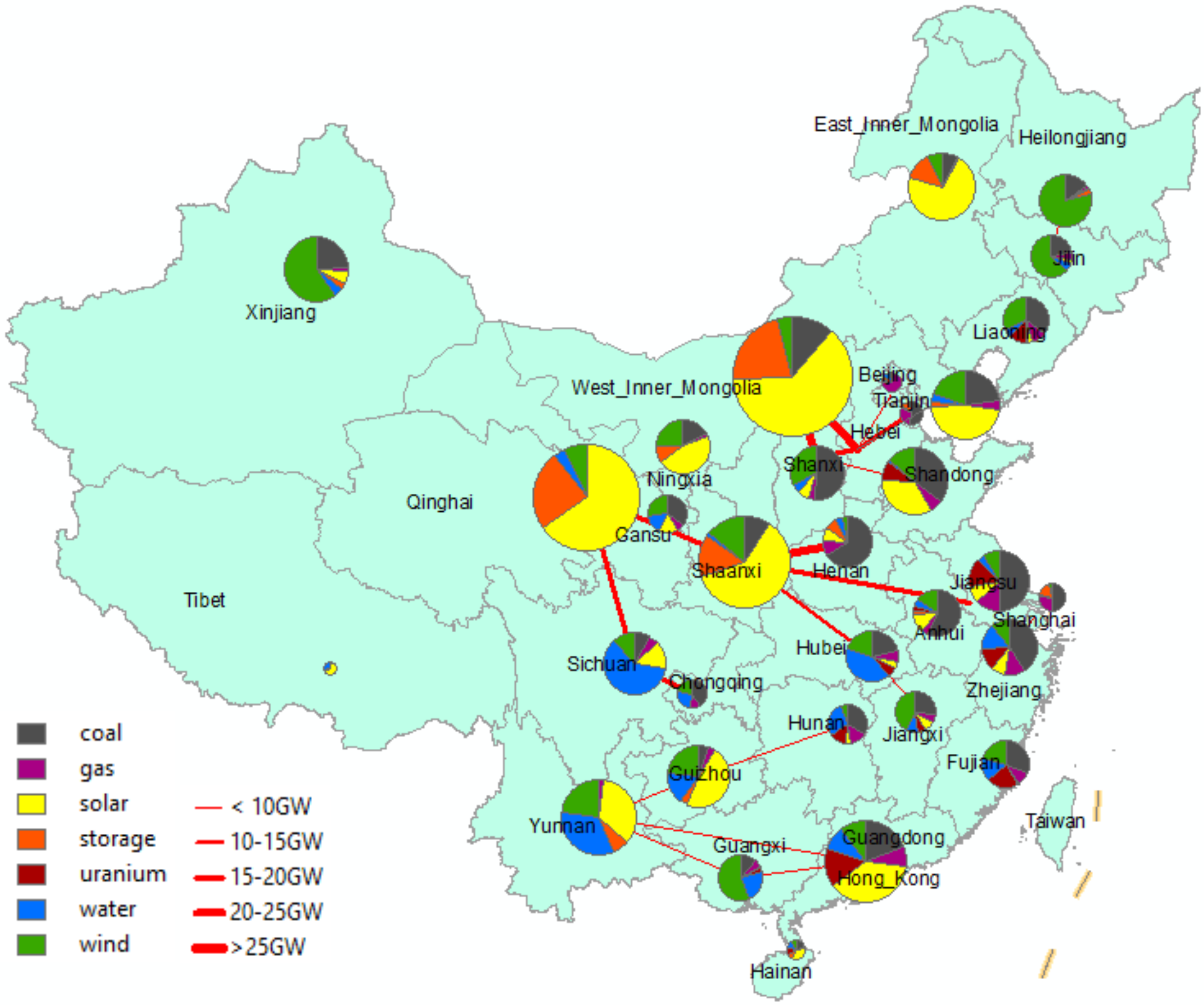


Figure 7 Provincial energy resource capacities and new transmission lines required by 2030 under the R scenario

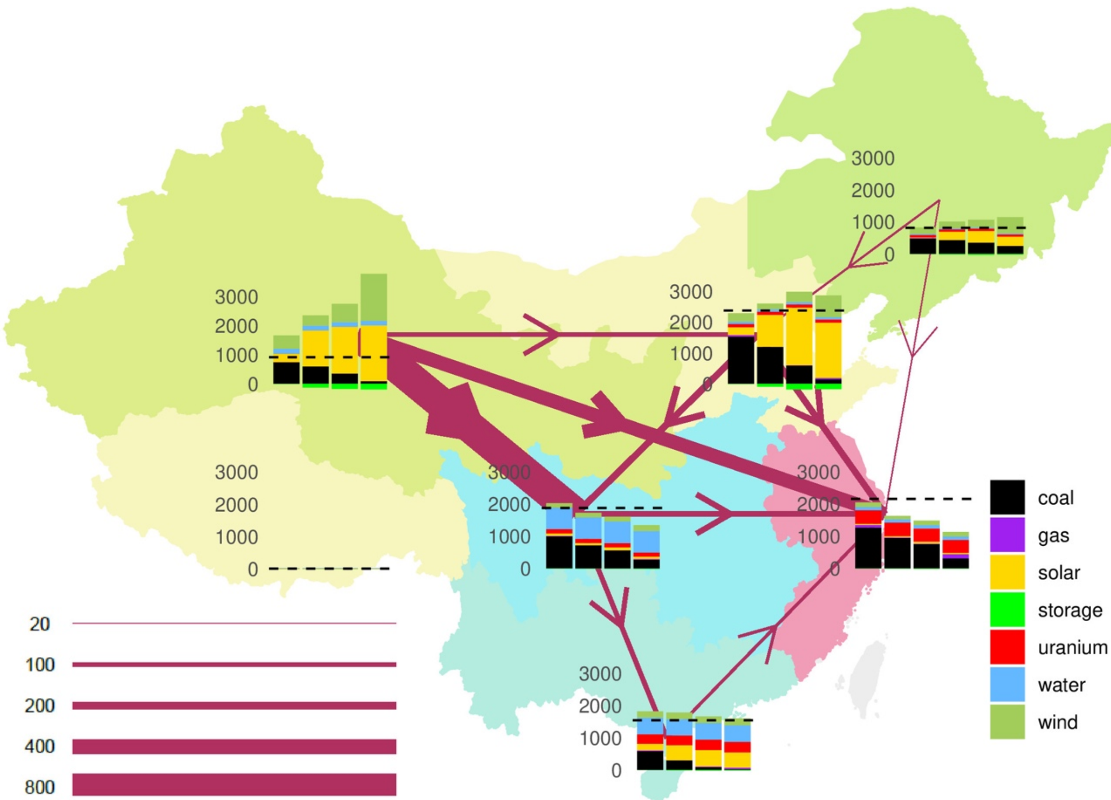


Figure 8 Regional generation, demand, and interregional transmission map for the R scenario in 2030, in TWh

As shown in Figure 8, the different grids are shaded in different colors based on the dominating energy source as the region decarbonizes. For example, the Northeastern grid is dominated by high wind energy penetration and is therefore shaded green and the Central grid is dominated by hydro electricity generation and is therefore shaded blue.

Each region shows a graph with four bars representing the generation for the four different scenarios in order of increased carbon reduction (from left to right: BAU, RE, C50, and C80, respectively). The dotted line across all bars in each set of generation graphs represents the yearly demand in 2030 in a given region, which stays constant across the four scenarios. The magenta arrows point in the direction of the transmission flow between two regions.

Regional disparities in demand, as well as resource availability, from hydro, solar, and wind, lead to different generation profiles for the BAU scenario (left most bar in each set). Across almost all regions, for the BAU scenario, generation closely matches the regional demand. The only exception is the Northwest grid where, even under the BAU scenario, is expected to export electricity to other regional grids. Under the R scenario, solar and wind resources rich regions increase their electricity generation dramatically, while regions with less solar and wind availability see a decrease in their overall generation. Decreases in generation across the Central, Eastern, and Southern grids, come mostly from decreased electricity generation from coal in these regions. This trend continues as the scenarios impose increasingly stringent decarbonization goals across the national grid, as shown in the third and fourth columns in each regional graph.

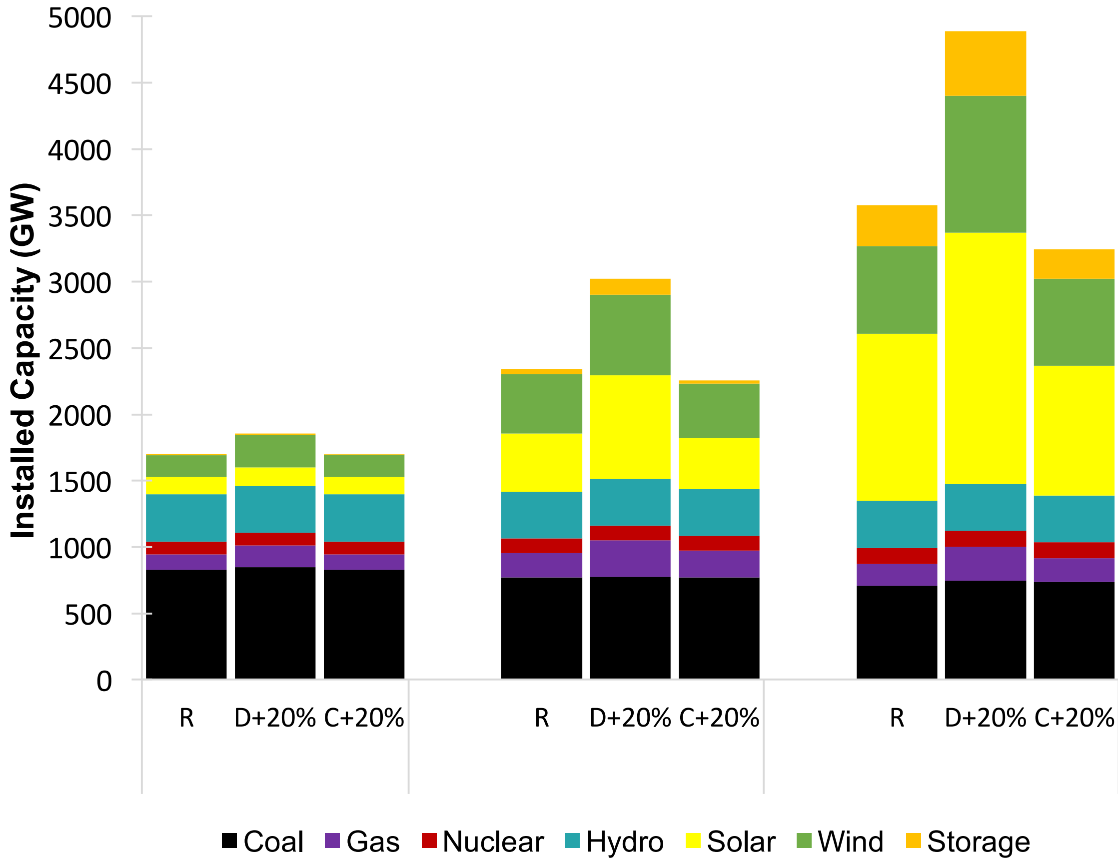
Under the R scenario, the Northwest grid is a net exporter of electricity to the Central, Northern, and Eastern grids. In particular, in 2030, under this scenario, the Northwest grid is expected to export 672, 287, and 90 TWh to the Central, Northern, and Eastern grids, respectively. On the other extreme, under the same scenario in 2030, the Eastern grid imports 287, 125, 111, 57 and 22 TWh from the Northwest, North, Central, South and Northeast grids. As outlined in this research, and as decarbonization priorities increase in the C50 and C80 scenarios, the total electricity generation in the Eastern grid further decreases becoming increasingly import-dependent to meet its demand. Future studies might consider studying the impact of a decrease in costs for offshore wind, and demand response technologies on the Eastern grid's reliance on imports to meet its demand under more stringent decarbonization goals by 2030 and beyond.

Under our current assumptions, we can observe that with the assumed decrease in costs for solar, wind and storage technologies the Northwest region emerges as a national supplier of carbon neutral electricity even as that choice requires increases in transmission capacity across the

Northwest and all other regions. Although not shown by arrows in the map above, one can infer that this trend is further exacerbated by more stringent carbon reduction goals across the national grid. In particular, we can see that under the C80 scenario, the Northwest grid generation exceeds its own demand by over 300%, while the Eastern grid produces only about 50% of its total electricity demand.

Sensitivity analysis and uncertainties

The power sector is a dynamic, evolving system affected by costs, demands, and other factors. We conducted sensitivity analyses on two key assumptions: the capital costs of renewables (solar, wind, and storage), and future electricity demand. Changes in both resource capacity and generation respond to changes in demand and costs. We consider two sensitivity scenarios: D+20% assumes that demand increases linearly 20% until 2030; C+20% assumes that the capital costs of solar, wind, and storage are 20% higher than under the R scenario (Figure 8). Under the D+20% scenario, by 2030 the capacities of solar and wind installations increase to 1,890 GW and 1,040 GW, respectively, whereas under the C+20% scenario, by 2030 the capacities of solar and wind installations decrease to 980 GW and 650 GW, respectively. The generation mix in the sensitivity scenarios follows a very similar pattern as in the capacity mix.


Installed Capacity (GW)
5000
4500
4000
3500
3000
2500
2000
1500
1000
500
0
R
D+20%
C+20%
R
D+20%
C+20%
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Nuclear
Hydro
Solar
Wind
Storage

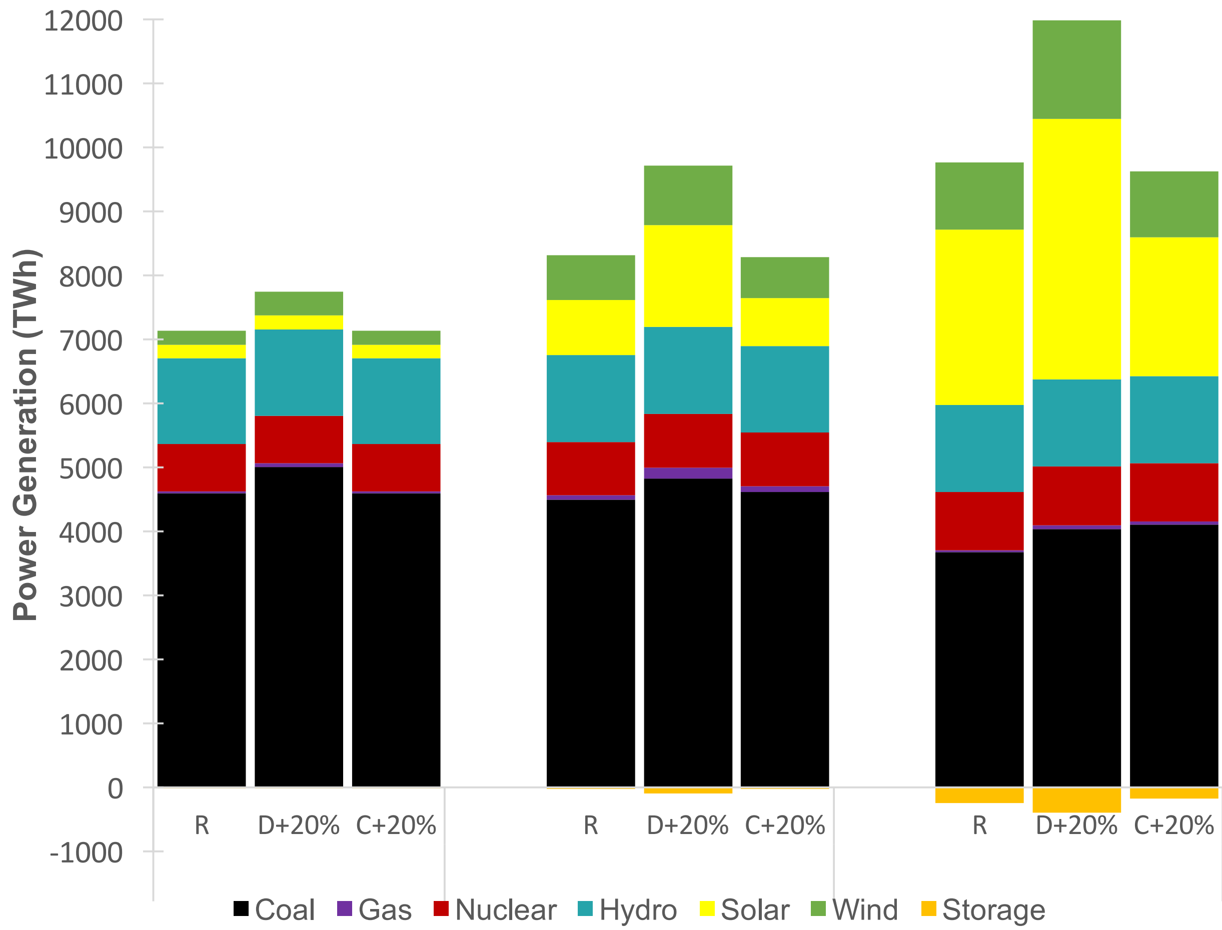


Figure 9 2030 Capacity mixes (top) and generation mixes (bottom) under the D+20% and C+20% sensitivity analyses

The large-scale decarbonization of the power sector requires that several processes take place simultaneously. First, both the resource capacity and transmission infrastructure must be scaled up quickly. Second, the investment needed for the infrastructure transformation must be acquired and dedicated. Third, social and economic equity must be addressed during the transition to lower carbon power systems. Any or all of those processes could encounter issues with the current physical framework and face obstruction from current stakeholders.

There is also uncertainty to deploy large scale of storage capacity to integrate the renewables. Our results show in the R scenario system requires 307 GW of storage capacity to provide about 250 TWh energy exchange (charge/discharge) and in the C80 scenario about 525 GW of storage capacity to provide about 388 TWh of energy from storage in 2030. The model assumes a four-hour charging/discharging cycle, those energy are achieved by an average of 250TWh/(365 day*307GW)=2.2 hour/day charge/discharge in the R scenario and 388TWh/(365 day*525GW)=2.0 hour/day charge/discharge in the C80 scenario.

Pumped hydro capacity in China in 2015 was about 25 GW, and has been expanding very quickly. It is estimated to have 100 GW, at least 80 GW by 2025, and potentially up to 120 GW by 2030.[24] In this case, to reach 307 GW capacity of storage under the R scenario in 2030, it would require battery storage to reach about 187 GW. With the increase of battery efficiency and performance, the needed storage capacity would be smaller. However, it indeed is very ambitious to deploy such a large scale of storage in a comparatively short time, about 12.5 GW annually during the studying period. Supply chain and life cycle management, economics of storage and policy support are essential to spur the large-scale deployment in order to make such transition happen.

Conclusions and discussion

The dramatic decrease in costs for renewable energy enables us to model China's power system and evaluate prospects for accelerating its decarbonization. Our modeling results show that if the levelized cost of energy (LCOE) for solar, wind, and storage follow recent global trends, by 2030 China would derive 62% of needed electricity from non-fossil sources. Total costs under the R scenario are 11% lower than under the BAU scenario. Under the carbon cap (C50) scenario, China could eliminate half of its 2015 carbon emissions from the power sector by 2030 with 6% lower cost, while delivering 77% of electricity from non-fossil sources. In the deep carbon cap (C80) scenario, an 80% emissions reduction from the 2015 level is technically feasible by 2030 but involves about a 21% higher cost than under the BAU scenario and a \$21/tCO_2 cost of conserved carbon. China has launched a national emissions-trading-system (ETS) with a price range of \$3-14.5/t CO_2, and the carbon price is expect to rise to an average of \$16.5/t CO_2, ranging \$4-20/tCO_2 by 2030.[15]

Although modeling results identify possible pathways to accelerate the decarbonization of China's power sector under the four scenarios developed for this study, the speed and scale of expanding the use of renewable energy could be enhanced or impeded by government policies, stakeholder interests, and capital market constraints, among other factors. Positive efforts could include target setting and cost reduction, as examplified in the renewable portfolio standard in California and elsewhere. Capacity auctions in China and India also create a pricing mechanism to lower the cost of renewables, especially wind and solar. Reforming the power market could create incentives to reduce institutional barriers to trading power across regions and to integrating renewable energy, thereby reducing the curtailment of wind and solar energy observed in the Chinese power sector.

China's power sector is in the midst of expansion and transition. The costs for energy from wind, solar, and storage are affected by many factors such as policy drivers and technological innovation. However, as indicated in the sensitivity analyses, the structural transformation of China's power sector is fairly consistent as long as the cost of renewable technology follows the global trend. This analysis indicates that fast decarbonization of China's power system is both technically feasible and economically beneficial to China's development, as well as offering the prospect of large emissions mitigation with a global impact.

Appendix

Methods and data

To most effectively model the impact of renewables on China's power system, we utilized the SWITCH-China computer model. SWITCH, which is a loose acronym for investment in solar, wind, hydro, and conventional technologies, is an optimization model that has the objective function of minimizing the cost of producing and delivering electricity based on projected demand through the construction and retirement of various power generation, storage, and transmission options available currently and at future target dates. The SWITCH-China model provides high resolution in both the temporal and spatial dimensions, to simulate the effect of the dramatically decreasing cost for incorporating renewable energy into the power grid.[13] SWITCH-China runs on a provincial scale and utilizes hourly data to simulate and optimize power system planning based on operational constraints. SWITCH optimizes both the long-term investment and short-term operation of the grid. The model incorporates a combination of current and advanced grid assets. Optimization is subject to reliability, constraints on operations, and resource availability, as well as on current and potential climate policies and environmental regulations.[16–20]

SWITCH-China's modeling decisions regarding system expansion are based on optimizing capital costs, operation and maintenance costs, and the variable costs for installed power plant capacities and transmission lines. Two primary options were available to help us decide which cost projections, from 2015 to 2030, to use in SWITCH-China. LBNL has developed projections of LCOE for utility-scale solar, wind, and storage to 2030. In addition, NREL's latest annual technology baseline (ATB) model projects capacity costs for solar and wind technologies.[21] Although the LCOE is useful in informing investment decisions for many situations, SWITCH-China uses capital, operation and maintenance, and variable costs to develop investment decisions.

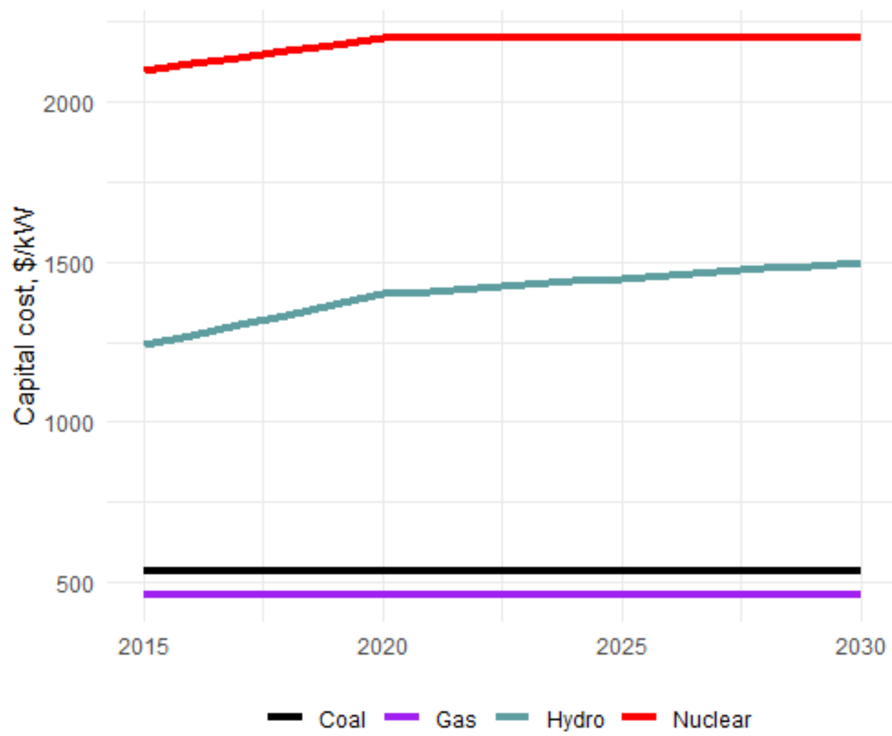
Thus SWITCH-China assumes that trajectories of capital costs for solar, storage, and wind technologies for the R and C50 scenarios will resemble NREL's ATB projections to 2030. Trajectories of capital cost for the baseline scenario utilize the original SWITCH-China cost assumptions for advanced technologies to 2030. Except for solar and wind, all other costs follow the original SWITCH-China cost assumptions for the two scenarios.

Non-renewables

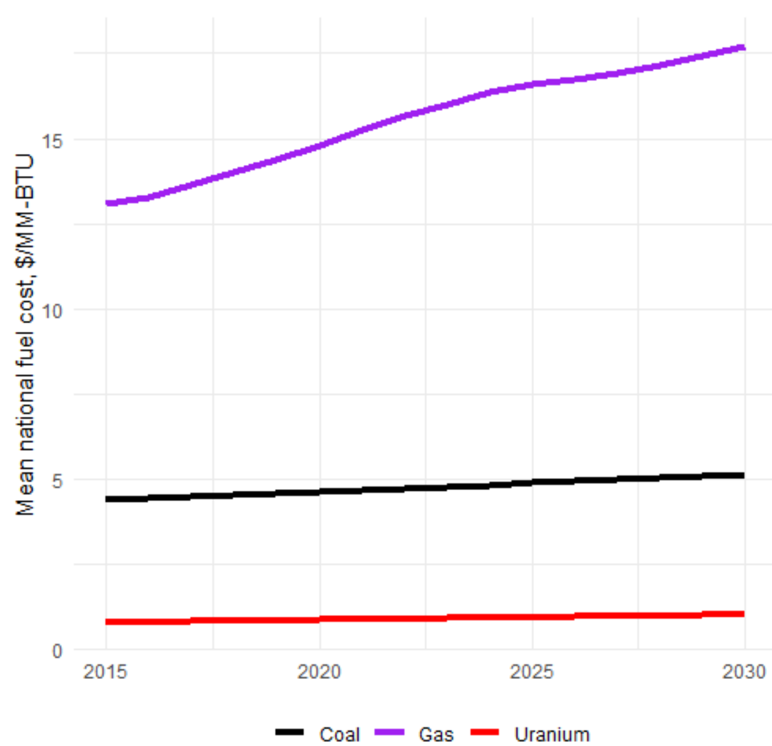
We first show the capital, operation and maintenance, and fuel costs associated with coal, gas, hydro and nuclear power plants in our model. We show the costs for solar, storage and wind, separately.

Capital costs

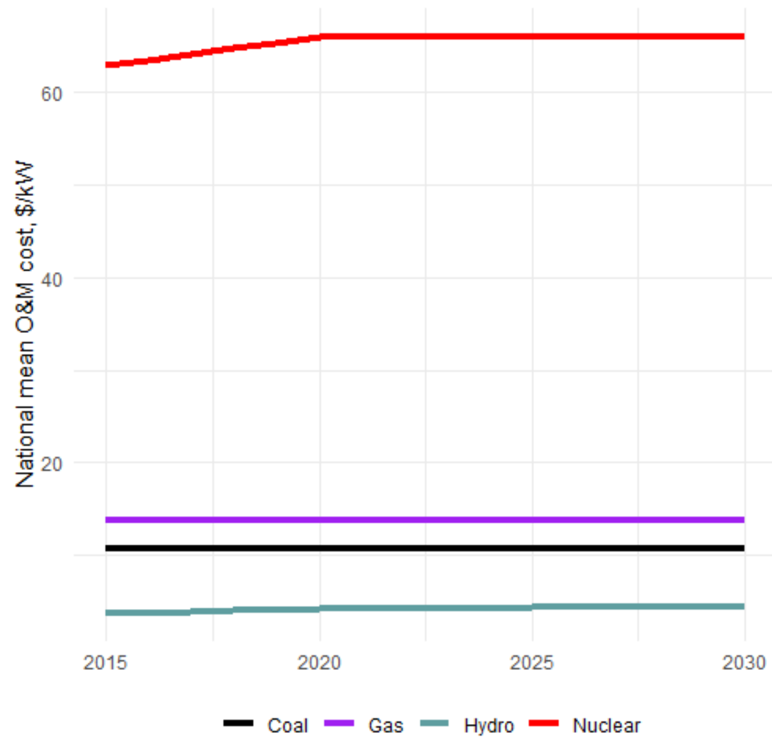
Capital costs are amortized over the expected lifetime of each generator or transmission line. Only those payments that occur during the period covered by the study are included in the SWITCH-China objective function.



(a) Capital costs



(b) Fuel costs



(c) Operation and maintainance costs

Figure 10 Costs of various non-renewable technologies under all scenarios, 2015 to 2030

Modeled capital costs for coal, gas, hydro and nuclear plants include trends to 2030 for different sizes and technologies of these plants. Figure 9(a) show the capital cost trend for the largest, and most common type of plant for each coal, gas, hydro, and nuclear power plant. Costs are assumed to increase for hydro and nuclear power plants but stay relatively constant for coal and gas plants between 2015 and 2030, respectively.

Fuel costs

Average national fuel costs for coal and gas in 2017 used in the SWITCH-China model are \$4.5/MMBtu and \$12.9/MMBtu, respectively. Fuel costs for coal, gas, and nuclear power plants all increase from 2017 to 2030 by 12.5, 23.7, and 21.4%, respectively. Provincial costs of coal are based on the national benchmark price at Qinhuangdao, minus/plus coal transportation costs. In

2030, coal, gas, and nuclear fuel costs increase to \$5.14, \$16.9, and \$0.98 per MMBtu, respectively. See Figure 9(b).

Operation and maintenance costs

SWITCH-China uses operation and maintenance costs in addition to capital and fuel costs to calculate total system costs over a period of time, see Figure 9(c). O&M costs are assumed to stay fairly constant for coal, gas, and hydro power plants. Only nuclear power plants O&M costs see a slight increase between 2015 and 2030. Hydropower plants have the lowest O&M costs in 2030 with \$4.5/kW. Coal operation and maintenance is slightly cheaper than gas-CC on a per kW basis, while nuclear is the most expensive unit to operate at \$66/kW in 2030.

Renewables and Batteries

We propose two different cost trajectories for battery storage, solar, and wind power technologies. Under the BAU scenarios, costs fall but remain relatively high until pass 2030. The R, C50, and C80 scenarios assume that lower costs for storage, solar, and wind power technologies are expected.

Capital and O&M

Under the different scenarios the capital costs for solar, storage and wind technologies all decrease. Under the BAU scenario, we assume that capital costs in 2030 are lower than in 2015 by 26, 31, and 6% for solar, storage, and wind technologies, respectively. On the other hand, under the low cost assumption, applied in the R and C scenarios in the main study, 2030 capital costs for solar, storage and wind, are lower than 2015 costs by 80, 57, and 66%, respectively.

Our capital costs assumptions for the Low Cost scenario for solar are a function of our estimates for the LCOE in 2030 expected given historical trends. We also directly estimate the capital costs for storage technologies from 2018 to 2030. Wind capital costs are informed by the 2018 NREL Annual Technology Baseline study.

Our estimates for the O&M costs for these three technologies in our model are equal to 1% of the capital costs of that given technology for that given scenario.

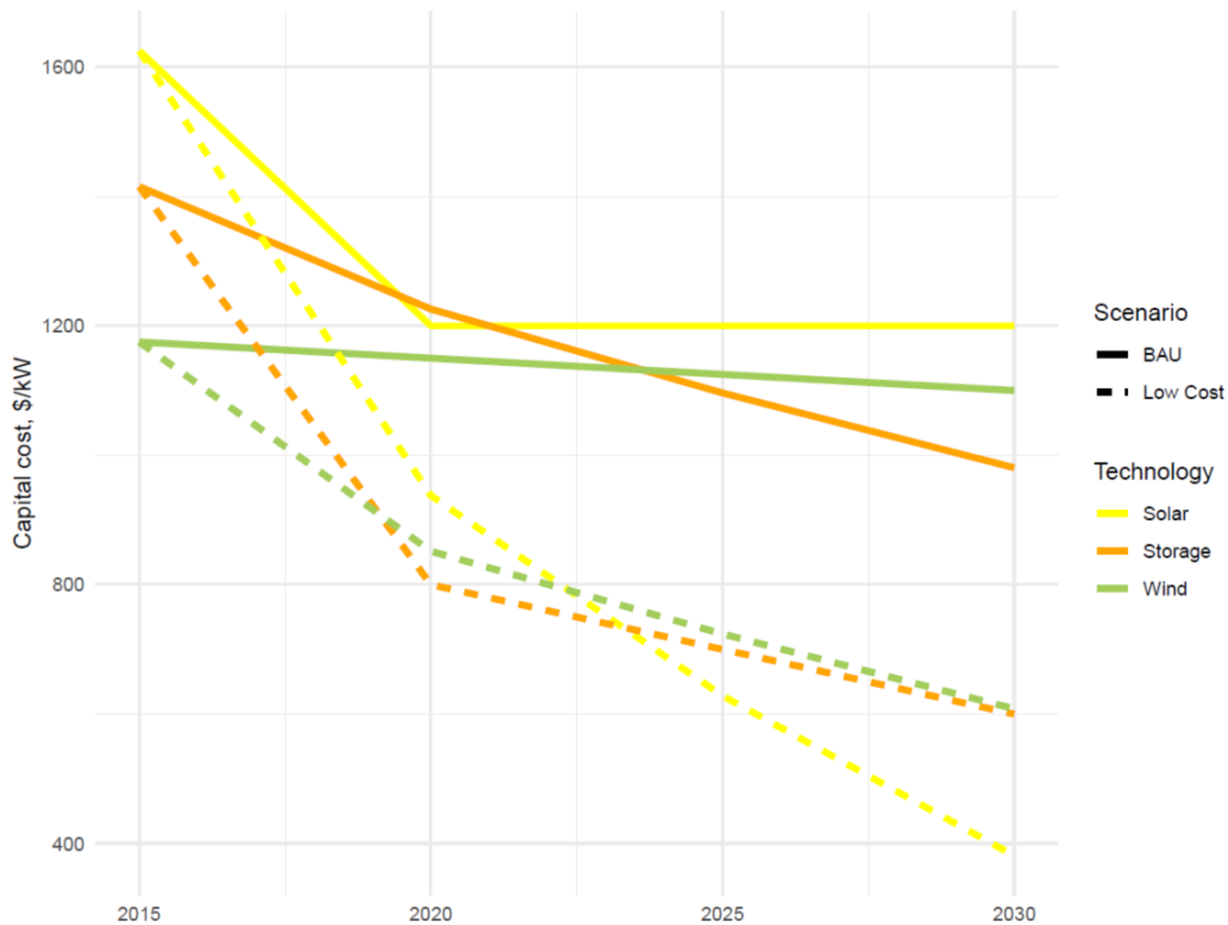


Figure 11. *Capital costs of wind, solar, and storage technologies under BAU and Low Cost scenarios, 2015 to 2030*

LCOE

We compare the levelized cost of electricity (LCOE) for solar, storage, and wind technologies between 2015 and 2030 under the two different cost scenarios in our model. We use slightly different ways to calculate or estimate the LCOE for the three technologies depending on the cost scenario. In the BAU cost scenario, solar and wind technologies LCOE calculations assume a national average capacity factor and a 20-year lifetime. In the BAU cost scenario, storage LCOE is calculated with our assumed capital cost trends for the same cost scenario, a 4-hour charge capacity, 300 charge cycles per year, and a 10 year lifetime. In the Low Cost scenario we estimate the solar LCOE trajectory after 2020 reaching an estimate of about 1.5 cents per kWh in 2030. The capital costs for solar are then calculated using this LCOE and the national average capacity factor for PV solar in China. For wind, we assume the NREL capital costs estimates, a national average capacity factor for wind turbines in China, as well as a 20-year lifetime for each turbine. Finally, for storage technology, we base our LCOE estimates on the our estimated capital costs trajectories for the Low Cost scenario, a 4-hour charge capacity, 300 cycles per year, and a 10-year lifetime.

Demand

We project electricity consumption by province in 2030 using a log-linear regression model.[22] This model considers electricity consumption as a function of provincial gross domestic product (GDP), population, the percentage of total value added by tertiary industry out of total provincial GDP (tertiary share), and crude steel production. We assume that the average annual growth rate of GDP in each province from 2016 to 2020 follows the goal described in China's 13th Five-year Plan (FYP) for that province. We then assume that the average annual growth rate from 2021 to 2030 is half of that from 2016 to 2020. For provincial population, first we project population in 2020 based on each province's 13th FYP and then assume that from 2021 to 2030 population grows at half the rate assumed for 2016 to 2020. We fix the crude steel production in each province at its 2016 level. The log-linear model estimates a total of 8,757 TWh electrical usage in 2030 in China, which is close to LBNL's China 2050 Demand Resource Energy Analysis Model's current policy scenario (8,595 TWh)[3] and to the State Grid Energy Research Institute model's scenario 3, medium social-economic development (8,790 TWh). [23]

Description of SWITCH-China model

The objective function of the SWITCH-China model is to minimize the sum of (1) capital costs of existing and new power plants and storage projects; (2) fixed O&M costs incurred by all active power plants and storage projects; (3) variable costs incurred by each plant, including variable O&M costs, fuel costs to produce electricity and provide spinning reserves, and any carbon costs of greenhouse gas emissions; (4) capital costs of new and existing transmission lines and distribution infrastructure; and (5) annual O&M costs for new and existing transmission lines and distribution infrastructure. Table 5 presents the SWITCH-China calculations of the factors presented above.

$\mathbf{min}\,\boldsymbol{C}$	**Total cost**
$= \sum_{T,i} G_{T,i} \times c_{T,i}$	Generation capital costs
$+ \sum_{g,i} G_{g,i} \times x_{T,i}$	Generation fixed costs
$+ \sum_{T,i} O_{T,t} \cdot (m_{T,t} + f_{T,t} + C_{T,t}) \cdot hs_t$	Generation variable costs
$+ \sum_{a,a',i} T_{a,a',i} \cdot l_{a,a'} \cdot t_{a,a',i}$	Transmission and distribution costs

Where: T denotes generation technology, g denotes projects, i denotes time period, t denotes hourly time points, and a denotes load areas.

The model includes five primary sets of constraints: those that ensure that the load is satisfied; those that maintain the stipulated capacity reserve margin; those that require maintaining operating reserves; those that enforce technology-specific targets (for example, wind and solar development plans, nuclear development plans, non-fossil energy targets, and other technology targets); and those that impose a carbon cap.

The SWITCH-China model employs multiple levels of temporal resolution to simulate power system dynamics throughout the period 2015 to 2030. The model considers investment periods in months, days, and hours. A single investment period contains historical data from 12 months, two days per month (the peak and median load days), and six hours per day. Each optimization considers three five-year investment periods: 2015 to 2020, 2020 to 2025, and 2025 to 2030, resulting in (3 investment periods) (12 months/investment period) (2 days/month) (6 hours/day) = 432 study hours during which the system is dispatched. Compared with simulating consecutive hours, simulating representative hours reduces computing time by a factor of 10, from 20 to 30 hours to about 2 to 3 hours. Additional study hours can be incorporated if the power system derived from the initial 432-timepoint optimization fails to meet load in any hour during the post-optimization dispatch check.

The output of generators that use renewable resources can be correlated not only among the sites of those resources but also with electricity demand. To account for those correlations, SWITCH-China employs time-synchronized historical hourly load and generation profiles for locations throughout China. Each date in a future investment period corresponds to an actual date from 2015 for which historical data are available regarding hourly loads, simulated hourly wind and solar capacity factors, and monthly hydroelectric availability. Hourly load data are scaled up to project future demand, while the availabilities of solar, wind, and hydroelectric resources are derived from historical data.

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