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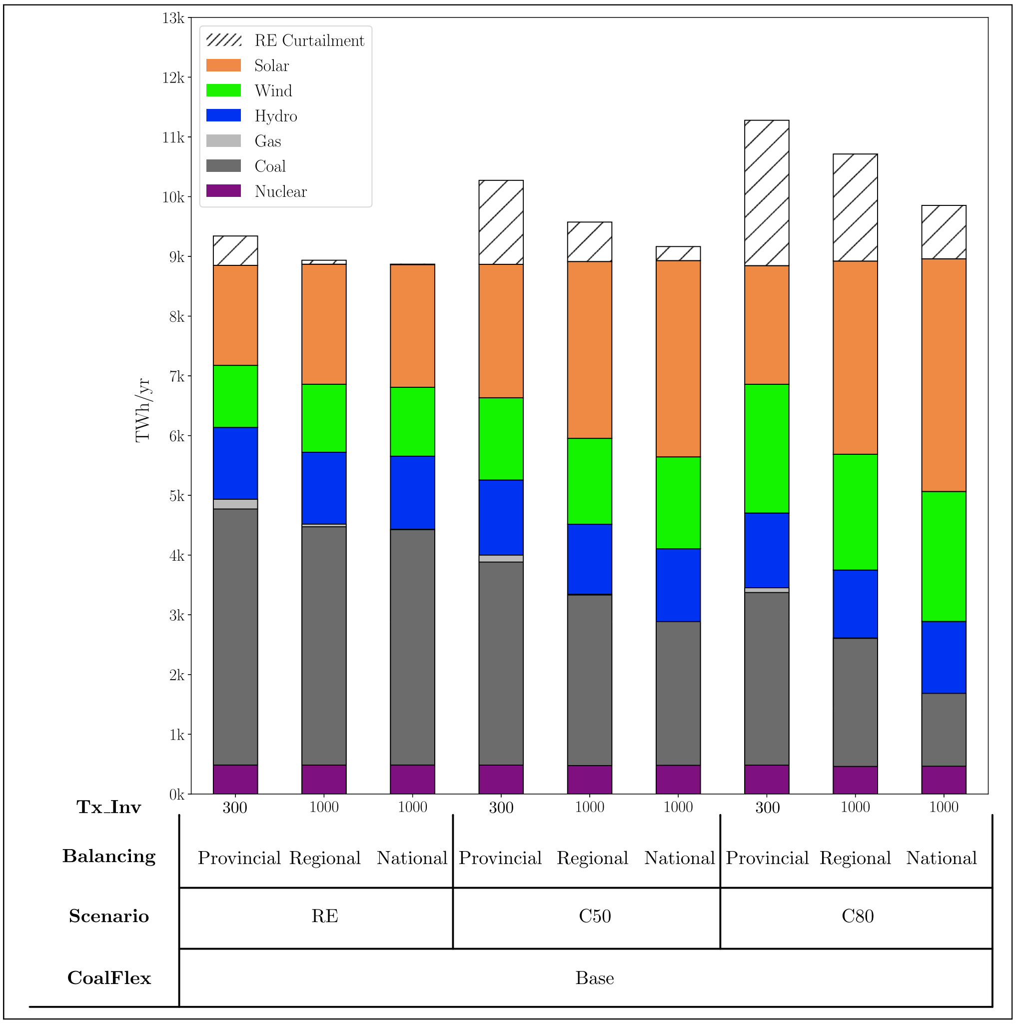
Large balancing areas and dispersed renewable investment enhance grid flexibility in a renewable-dominant power system in China



Jiang Lin, Nikit Abhyankar, Gang He, Xu Liu, Shengfei Yin

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Highlights

Retrofitting coal power plants offers marginal improvements in renewable utilization

Larger balancing areas give flexibility benefits with renewable curtailment reduction

Dispersed renewable investment further reduces curtailment and coal generation

Combining larger balancing areas and dispersed renewables gains the greatest impact

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Large balancing areas and dispersed renewable investment enhance grid flexibility in a renewable-dominant power system in China

Jiang Lin,[1,2,5,6,*] Nikit Abhyankar,[1,5] Gang He,[3] Xu Liu,[4] and Shengfei Yin[1]

SUMMARY

Renewable energy is poised to play a major role in achieving China's carbon neutrality goal by 2060; however, reliability and flexibility is a big concern of a renewable-dominant power system. Various strategies of enhancing flexibility are under discussion to ensure the reliability of such a system, but no detailed quantitative analysis has been reported yet in China. We combine the advantages of a capacity expansion model, SWITCH-China, with a production simulation model, PLEXOS, and analyze flexibility options under different scenarios of a renewable-dominant power system in China. We find that a larger balancing area offers direct flexibility benefits. Regional balancing could reduce the renewable curtailment rate by 5–7%, compared with a provincial balancing strategy. National balancing could further reduce the power cost by about 16%. However, retrofitting coal power plants for flexible operation would only improve the system flexibility marginally.

INTRODUCTION

The Chinese power sector is among the world's top emitters, accounting for about 14% of global energy-related carbon emissions (IEA, 2020). Falling renewable and storage costs have created significant new opportunities for rapid power sector decarbonization that were not possible a few years ago. Some recent studies using the latest renewable energy and battery cost trends have shown that by 2030, China can cost-effectively decarbonize up to 60% of its power sector (He et al., 2020).

Recognizing the growing opportunities to boost its climate leadership and sustainable development, China pledged to reach carbon neutrality by 2060 in September 2020. Further, it set a target for installing 1200 GW of solar and wind power by 2030 (MFA, 2020). Although rapid decarbonization of the power sector and electrification of other end-use sectors are considered key strategies to reach carbon neutrality, there is still considerable debate within China on the operational challenges of maintaining a renewable-dominant power system (ERI, 2015; He, 2020). In this article, we assess the operational feasibility of near-complete decarbonization of China's power sector by 2030 using hourly system dispatch and operations simulation at the provincial level. The measures under consideration include enlarging balancing areas beyond the current provincial boundary, expanding transmission capacity, making existing coal power plants more flexible, and siting renewables near load centers.

Overcoming the operational challenges of integrating higher penetrations of renewable energy into the grid requires changes in operations, markets, and investment planning. Existing research on addressing renewable variability and promoting renewable integration has focused on several main roadmaps (Apt and Jaramillo, 2014; Milligan et al., 2015): transmission (Schaber et al., 2012), larger balancing area, storage (Schill, 2020), demand response, power system operation, electricity market, and integrating supply-load transmissions (Zhang et al., 2017). Cochran et al. (2015) and Martinot (2016) summarize the key grid integration strategies and identify markets and system operations as the lowest-cost sources of increased grid flexibility (Cochran et al., 2015; Martinot, 2016). Batteries and other energy storage resources, especially long-duration energy storage, also become crucial at higher levels of penetration (Schill, 2020; Sepulveda et al., 2021). Demand response could be used in enhancing grid flexibility, offering a viable, cost-effective alternative to supply-side investments (Cappers et al., 2009; Coughlin et al., 2008; McPherson and Stoll, 2020). Although the coal phaseout becomes inevitable to reach carbon neutrality in China, the carbon

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market provides another tool accelerate this process (Mo et al., 2021). Market design is also vital to ensuring resource adequacy and sufficient revenues to recover costs when those resources are needed for long-term reliability with high penetration of renewables (Milligan et al., 2016), and to align with other market instruments such as emission trading systems (ETS) (Mo et al., 2021; Peng and Poudineh, 2019).

At the regional scale, NREL's Renewable Electricity Futures Study explores the implications and challenges of very high renewable electricity generation levels in the U.S. It shows it is possible to achieve an 80% renewable grid by 2050 with grid flexibility coming from a portfolio of supply-side and demand-side options, including flexible conventional generation, grid storage, new transmission, more responsive loads, and changes in power system operations (Mai et al., 2014; NREL, 2012; Osmani et al., 2013). A more recent study shows reaching 90% carbon-free electricity by 2035 is possible because of plummeting solar, wind, and storage costs (Phadke et al., 2020). Similar results are reported in the E.U., India, and other parts of the world. For example, the E.U. Energy Roadmap (2050) shows the E.U. could achieve a 100% renewable grid by emphasizing the role of storage and hydrogen (Energy Roadmap 2050, 2012; Zappa et al., 2019). Deshmukh et al. (2021) and Abhyankar (2020) assess renewable integration in India and find that diurnal energy storage equivalent to about 10% of the average daily renewable energy generation would be needed to reliably integrate renewable energy penetration of up to 40-50% (Abhyankar et al., 2020; Deshmukh et al., 2021).

Several studies assess the overall potential of power system decarbonization in China; very few examine the key operational-level details and challenges. China's Energy Research Institute (2015) explores pathways by which renewable energy could account for over 60% of the energy consumption and over 85% of the electricity consumption by 2050 (ERI, 2015). He et al. (2020) determine that China could have more than 60% of its electricity from low-carbon sources by 2030 facilitated by low-cost renewables (He et al., 2020). Yuan et al. (2020) use Jilin province as a case study for evaluating system flexibility at a 40% renewable penetration rate and proposed upgrading coal and natural gas plants and integrating supply, transmission, load, and storage assets (Yuan et al., 2020). Ding et al. (2021) use Jiangsu as an example and show that retrofitting coal units to meet peak load could improve system flexibility (Ding et al., 2021). Lin et al. (2019) and Abhyankar et al. (2020) study the benefits of economic dispatch and electricity markets in Guangdong and the Southern Grid (Abhyankar et al., 2020; Lin et al., 2019). Researches also discuss the role of micro-grid, demand response, and integration with transportation and building sectors to reduce renewable curtailment and increase system flexibility with high renewable penetration. However, the interactions and trade-offs between these approaches are not well understood. Our work fills this critical gap by assessing the impact and effectiveness of different approaches and providing insight into accelerating China's renewable energy development.

RESULTS

Figure 1 presents the installed capacity and generation mixes across the four main carbon mitigation scenarios in 2030 under the current provincial balance practice. The results show that the curtailment rate of renewable energy increases significantly as their penetration rate increases (up to 37% if the current provincial balancing model continues). This is expected, as the current operational practice is unlikely to support China's ambitious plan to transition to a renewable-dominant power system to meet its carbon neutrality target. Therefore, we aim to evaluate several options for addressing operational challenges more thoroughly as China's power system evolves into a renewable-centric system.

Overall, allowing (through retrofit) coal power plants to be more flexible offers little improvement in renewable energy utilization in all scenarios. As shown in Figure 2, renewable curtailment remains almost the same (flex 25 vs. base case) under all scenarios (BAU, RE, C50, C80) with provincial balancing, as does coal power generation. In fact, curtailment of renewable energy more than doubles from the RE to the C50 scenario, indicating that the current provincial balancing model is inadequate to solve the renewable integration challenge even when retrofitting coal power plants for more flexibility. The maximum curtailment of renewable energy tends to occur in the spring because of lower seasonal demand (Figure 2B).

However, enlarging balancing areas reduces renewable curtailment significantly while maintaining grid reliability constraints (with a reserve margin of 15%). Figure 3 shows national annual generation and average dispatch in selected months under different balancing area scenarios. Moving from provincial balancing to regional balancing significantly reduces curtailment rates (6% under RE, 7% under C50, and 5% under C80). Under a national balancing scenario, additional renewable generation can be utilized,

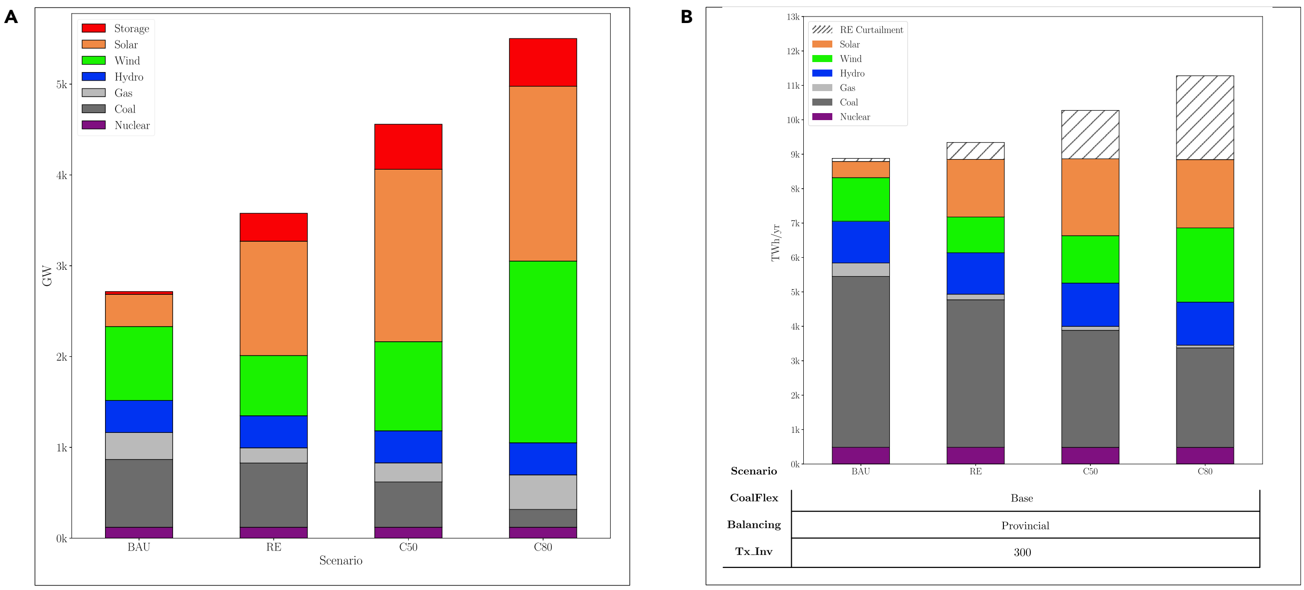

Figure 1. Installed capacity and generation in 2030 with the provincial balancing

(A) Installed capacity.

(B) Generation.

and curtailment rates can be further reduced (11%, 15%, and 21% reduction under RE, C50, and C80, respectively, compared to provincial balancing). Similar patterns hold for seasonal renewable curtailment (Figure 3B); regional and national balancing leads to significant reductions in renewable curtailment.

Moreover, the effect of reducing coal power generation increases with larger balancing areas and more renewable integration (2% under RE, 8% under C50, and 31% under C80 with regional balancing; and 6% under RE, 21% under C50, and 45% under C80 with national balancing). Again, the role of enlarging balancing areas becomes central as China's power system moves toward a greater degree of renewable generation.

As renewable power costs further decline and China raises its ambition for renewable installation, the question becomes: What is the more balanced way to build out renewable capacity across the country? Figure 4 shows the difference in generation from different fuel types between low and high transmission investment costs, which would encourage more locally dispersed renewable investment. As shown in Figure 4, renewable curtailment and coal generation drop in all scenarios with a 1000 USD/MW-km transmission investment cost. This result demonstrates that investing in renewable energy in a more geographically dispersed way can achieve additional reductions in both curtailment and coal generation. Even under the provincial balancing scenario, reductions in the curtailment rate (4–10%) and in coal generation (6–9%) can be achieved with a high transmission cost compared with low transmission cost. These benefits are comparable with establishing regional balancing areas.

Overall, combining larger balancing areas and more locally based renewable investment could have the highest impact. As shown in Figure 5, with regional balancing and more local renewable development, curtailment rates drop to 2%, 13%, and 26% under RE, C50 and C80 scenarios (compared with 15%, 28%, and 37% with provincial balancing and less dispersed renewable investment), respectively, whereas coal generation declines by 7%, 16%, and 26% under RE, C50, and C80 scenarios, respectively.

Under national balancing and more local renewable development, curtailment rates reduce to 0.2%, 5%, and 13% under RE, C50, and C80 scenarios, respectively; coal generation declines 8%, 29%, and 58% under RE, Ce50, and C80 scenarios, respectively.

These operation strategies that enhance system reliability would also reduce the average wholesale costs of electricity, as shown in Figure 6. Under the RE scenario, adopting a regional balancing strategy could

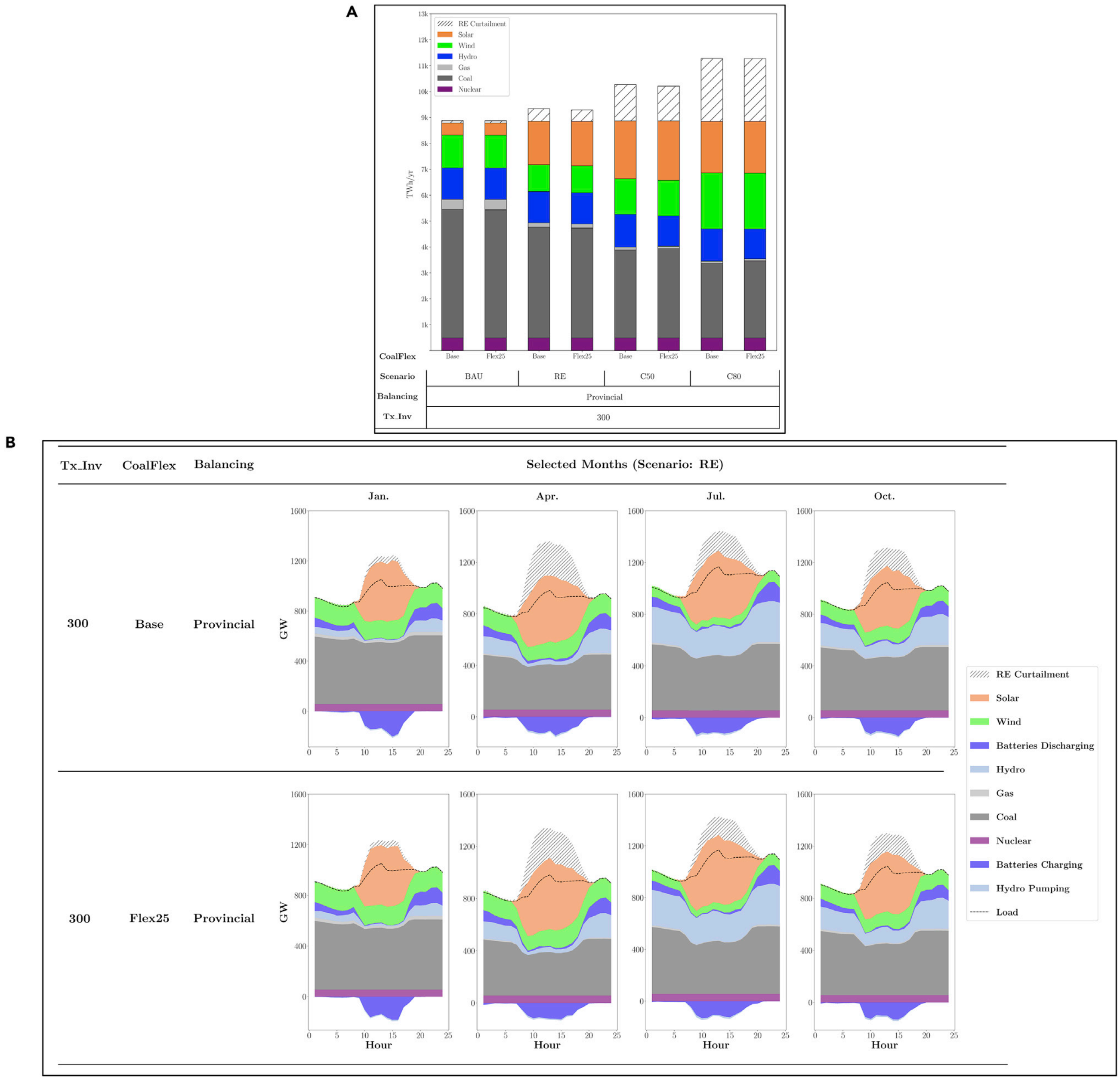

Figure 2. China national annual generation and average dispatch with different coal flexibility

(A) National annual generation.

(B) National average dispatch under RE scenario.

reduce the average cost by 5.1%, and by 6.1%, with national balancing. Under the C50 scenario, similar cost savings would be 7.6 and 12%, respectively.

DISCUSSION

As China scales up its renewable development ambitions, there is a growing concern about how China could cost-effectively maintain grid flexibility—and thus reliability—while meeting its 2060 carbon neutrality target. Technically retrofitting coal power plants has often been considered a first choice in China. However, our analysis shows that retrofitting coal power plants contributes little to total system

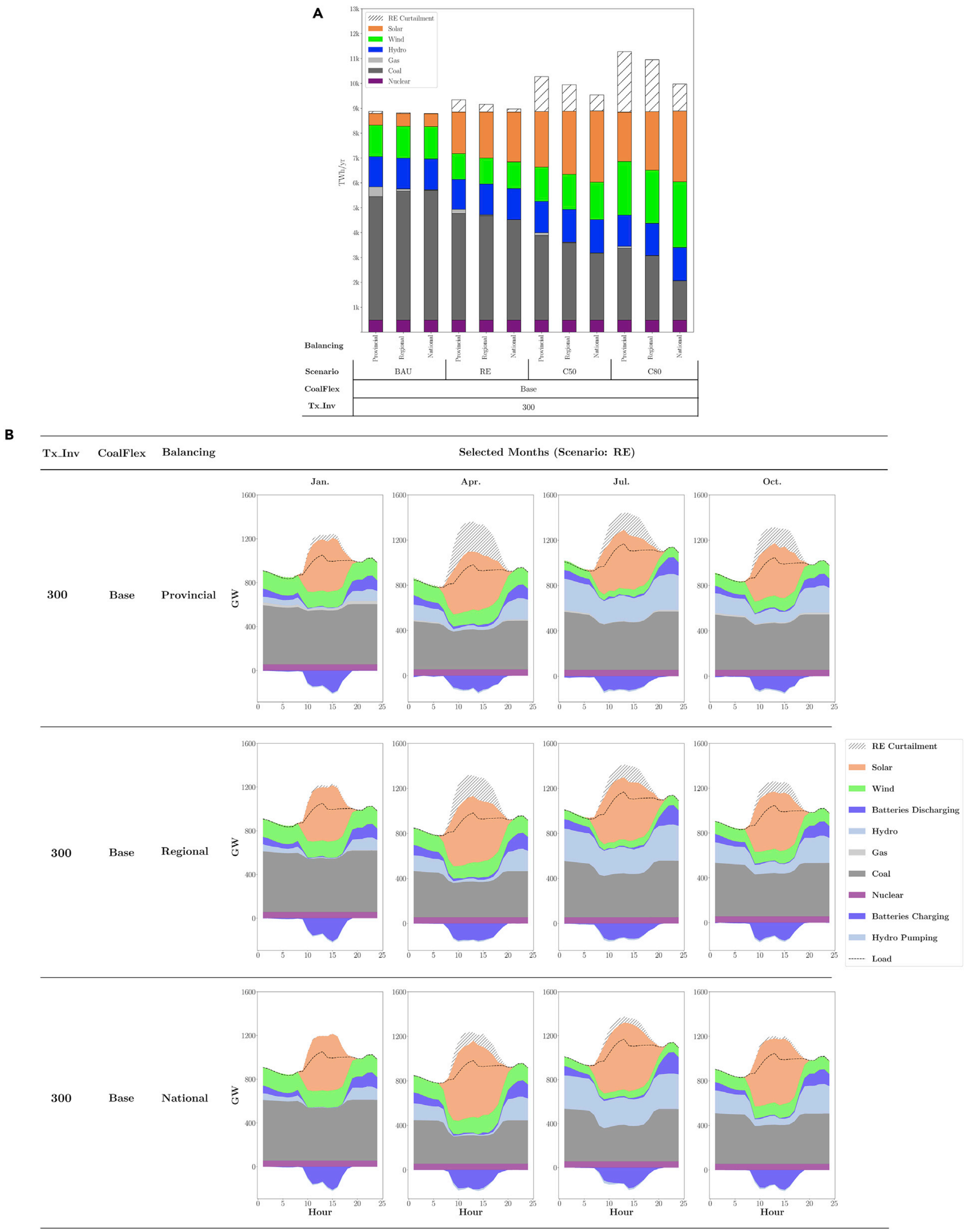

Figure 3. China national annual generation and average dispatch under different balancing strategies

(A) National annual generation.

(B) National average dispatch under RE scenario.

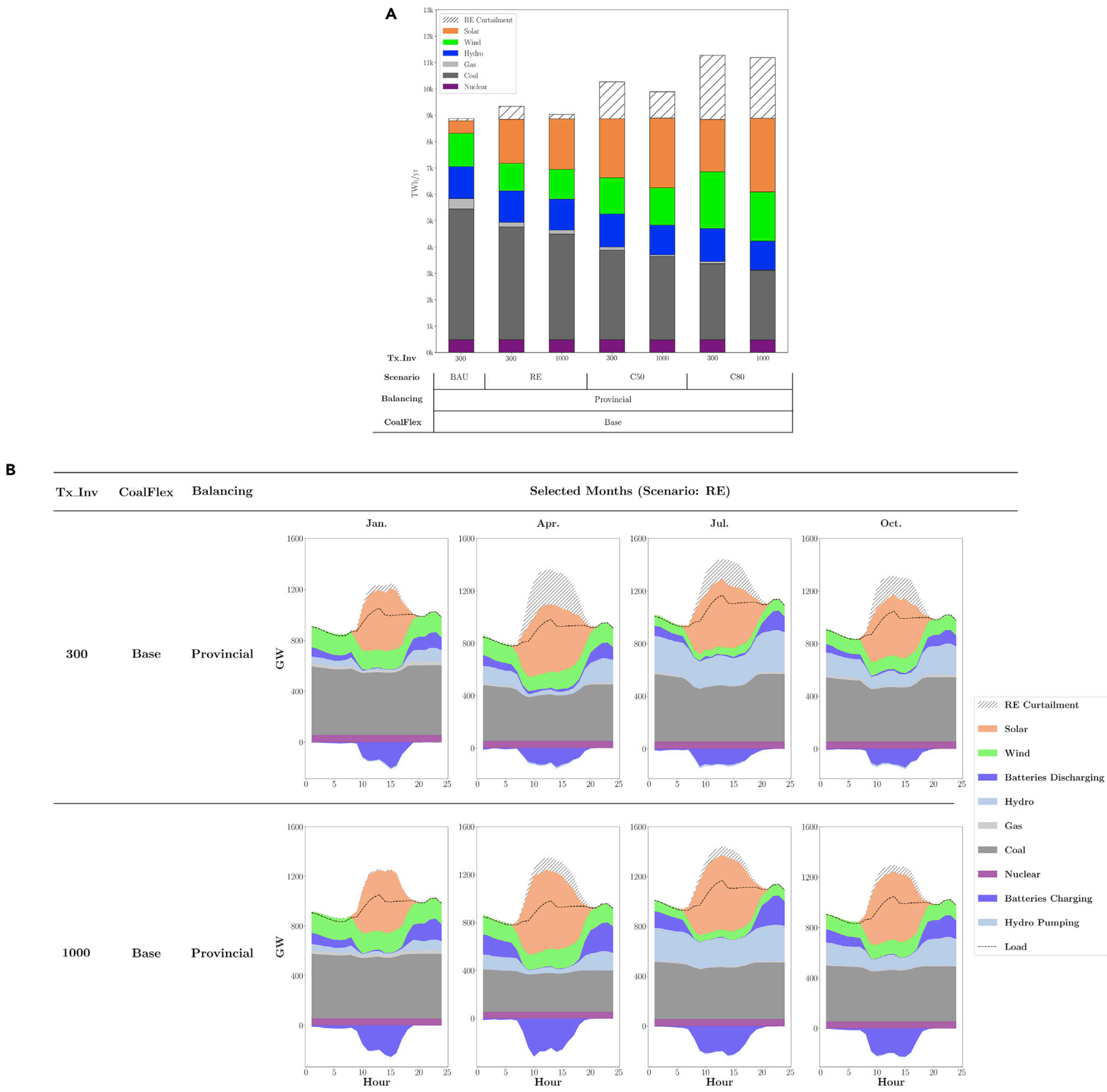

Figure 4. China national annual generation and average dispatch with two transmission cost settings

(A) National annual generation.

(B) National average dispatch under RE scenario.

flexibility, renewable integration, and system reliability, primarily because there are already a sufficiently large number of coal power plants available in China

In contrast, reforming its current power system operation practices and market rules to allow larger balancing areas, such as at a regional level, would significantly contribute to enhancing flexibility, integrating renewables, and ensuring grid reliability. Regional power markets, such as those considered in the southern grid region of China, could be instrumental in facilitating such a transition.

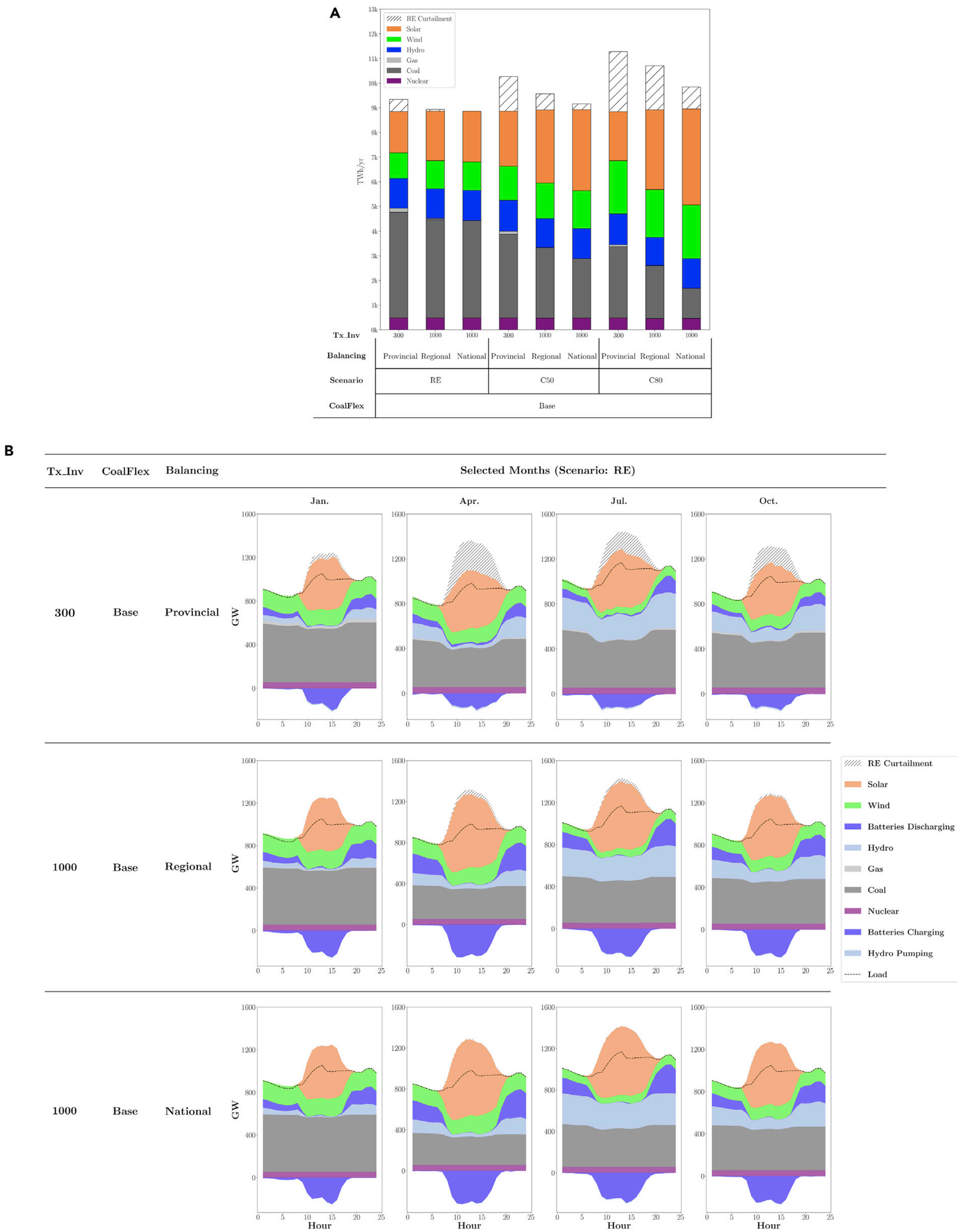

Figure 5. China national annual generation and average dispatch with two transmission cost settings under different balancing strategies

(A) National annual generation.

(B) National average dispatch under RE scenario.

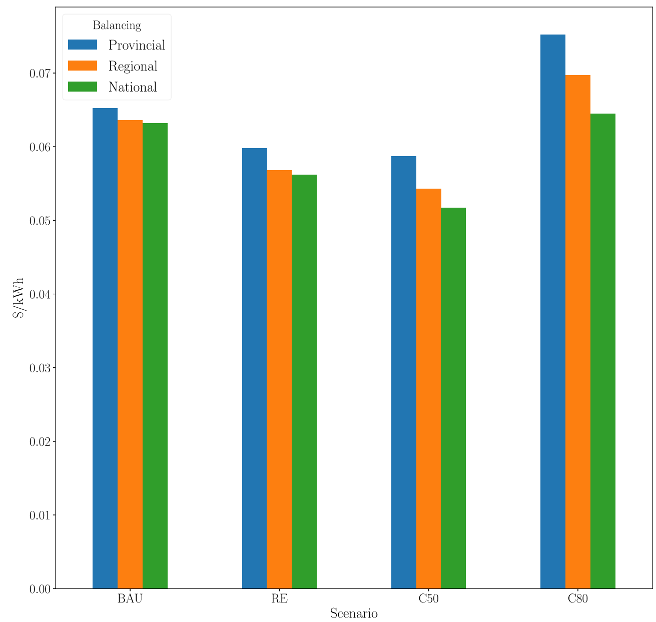

Figure 6. Average wholesale cost of electricity (fixed costs included) under different scenarios

As the costs of renewables continue to decline, they become more competitive against coal power in more load-center regions and provinces. Investing in such local resources would not only save investment in long-distance transmission but also reduce curtailment and enhance reliability. In addition, local generation projects would also lead to more local investment and jobs. Thus, these local economic benefits would lead to more political support for a clean energy transition among the Chinese provinces, which tend to trail the national government in clean energy and climate ambitions.

Combining such operation, market reform, and investment strategies will likely yield the best outcome for integrating renewable energy and enhancing reliability. Such combined approaches are essential to achieve deep decarbonization of China's power system.

These results suggest that China should accelerate its power system reform, allowing regional markets and enlarging operation balancing areas. Leaving this system operation challenge (as well as resource planning) unresolved would seriously hinder renewable development. Fortunately, regional dispatch centers across China's six regional grids already exist; their functions need to be strengthened. Furthermore, wholesale market development should allow price signals to play a larger role in affecting power demand and supply. As we have shown previously, the regional market generates economic benefits for all provinces within the regional grids.

As costs of renewable and storage technologies decline further, it will become more attractive for economically vibrant provinces to develop in-province resources. The current planning approaches need to evolve, incorporating these trends to allow for more diversity in China's infrastructure portfolio, enhancing system resilience, energy security, and local political support in Chinese provinces. As China accelerates its renewable energy transition to reach carbon neutrality by 2060, it is essential to simultaneously develop a comprehensive set of the institutional options discussed above to ensure a smooth transition to a clean and reliable grid in China.

Limitations of the study

The study does not consider the detailed procedure of balancing strategies, while only limiting to the transmission hurdle rates. A more comprehensive renewable and load forecast would also bolster the analytical studies conducted in this paper. Also, we omit the potential impact from CCS facilities, which might provide more insights based on the current model designs.

STAR★METHODS

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AUTHOR CONTRIBUTIONS

J. L., N. A., and G.H. came up with the idea of the paper. J. L., G. H., and X. L. collected and calibrated the input policy and asset data used in the paper. N.A. and G.H. conducted the numerical experiments. J. L., X.L., N. A., and G. H. performed the technical analyses of the results, provided policy recommendations, and wrote the main body of the manuscript. S. Y. processed the results and finalized the submission version.

DECLARATION OF INTERESTS

The authors declare no competing interests.

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STAR★METHODS

KEY RESOURCES TABLE

REAGENT or RESOURCE	SOURCE	IDENTIFIER
Deposited data		
Note: The complete data set could be found upon request.		
Software and algorithms		
SWITCH	https://github.com/switch-model/switch	2.0.6
PLEXOS	Energy Exemplar, LLC	8.3

RESOURCE AVAILABILITY

Lead contact

Further information and requests for resources should be directed to and will be fulfilled by the lead contact, Jiang Lin (j_lin@lbl.gov).

Materials availability

The study did not generate new materials.

Data and code availability

- The model and sources of the data sets supporting the current study have been presented.
- We carried out the studies using calibrated professional software. The code to reproduce the charts based on the results is available upon request from the lead contact.
- Any additional information required to reanalyze the data reported in this paper is available upon request from the lead contact.

EXPERIMENTAL MODEL AND SUBJECT DETAILS

There is no experimental model and subject discussed in this paper.

METHOD DETAILS

Numerical models for system planning and production cost simulation

Studies assessing the impacts of high renewable energy penetration on electric power systems use various optimization tools, namely production cost models, capacity expansion models, or a combination of these. Capacity expansion models incorporate both fixed and variable costs of existing and planned generation, storage, demand-side resources, and transmission infrastructure to choose an optimal mix of assets to meet electricity demand across future years. Production cost models simulate grid dispatch using only variable costs for a given power generation mix and transmission capacity to meet electricity demand at the least cost. Typically, capacity expansion models have lower temporal resolution and a less detailed representation of the electricity system as they optimize the system across multiple years. Conversely, production cost models have higher temporal resolution (minutes to hours) and a more detailed representation of the electricity system but typically simulate the system across only one year.

We use PLEXOS, an industry-standard optimization software by Energy Exemplar used by grid operators and utilities worldwide. PLEXOS optimizes the unit commitment and economic dispatch decisions using mixed-integer programming to minimize an objective function of costs, subject to constraints including load, emissions, transmission, and generator ramp rate limits. We use the Xpress-MP 28.01.13 mathematical solver for the optimization, with a mixed-integer programming gap of 0.5%. We simulate grid dispatch using only variable costs and operational constraints for a given power generation mix and transmission capacity to meet electricity demand at the least cost. We use SWITCH-China for capacity expansion analysis based on the scenarios defined in He et al. (2020). The detailed energy modeling information for the SWITCH-China and PLEXOS can be found in subsequent sections

Based on He et al. (2020), we develop the following scenarios for assessing the operational feasibility of a decarbonized Chinese power system. First, the business as usual scenario (BAU) assumes the continuation of current policies and moderate cost decreases in future renewable costs. Second, a low-cost renewables scenario (RE) assumes the rapid decrease in costs for renewables and storage will continue. Third, a carbon constraints scenario (C50) caps carbon at 50% lower than the 2015 level by 2030. Fourth, a deep carbon constraints scenario (C80) further constrains the carbon emissions from the power sector to be 80% lower than the 2015 level by 2030. The detailed scenario settings with cost assumptions could be found in subsequent sections.

SWITCH-China modeling descriptions and assumptions

We provide the detailed modeling descriptions and assumption information for SWITCH-China in this section that are consistent with previous version of the model (He et al., 2016, 2020).

For the capacity expansion model, the objective function 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. The below table presents the SWITCH-China calculations of the factors presented above.

min 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: (1) power-load balance constraints; (2) stipulated capacity reserve margin constraints; (3) operating reserve constraints; (3) specific technology target constraints (e.g., wind and solar development plans, nuclear development plans, non-fossil energy targets, and other technology targets); (5) carbon emission capping constraint.

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 the 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.

PLEXOS modeling descriptions and assumptions

This section provides technical details regarding the PLEXOS model adopted in this paper that are first used in (Lin et al., 2019). The PLEXOS model is a unit commitment and economic dispatch model that minimizes the total operating cost of generation for a full year. More details are available in PLEXOS documentation from Energy Exemplar.

The objective function for each hour of the optimization can be simplified to:

$$min \sum_{i,t} GenerationCost_{i,t} + VoLL * UnservedEnergy_t + PriceofDumpEnergy * DumpEnergy_t$$

subject to several types of operational constraints, which will be further described.

The objective function has several components: i indexes each of the generators, which are in specific provinces within China and could be thermal (natural gas, coal, nuclear, other), hydro, or variable renewable resources like wind and solar. There are several thousand generators included in China. t indexes each hour in the optimization. The optimization is conducted for hourly intervals, at daily timesteps, one month at a time for a complete year. $GenerationCost_{i,t}$ is the total hourly operating cost of generator i, including the fuel costs ($FC_{i,t}$), operations and maintenance costs ($O\&M_{i,t}$), start/shutdown costs of thermal units ($SC_{i,t}$), and the emissions costs of fossil units ($EC_{i,t}$), as shown below.

$$GenerationCost_{i,t} = FC_{i,t} + O\&M_{i,t} + SC_{i,t}$$

Each component of $GenerationCost_{i,t}$ is defined as follows:

$$FC_{i,t} = FuelPrice_i \times HeatValue_i \times HeatRate_i \times \sum_t Generation_{i,t}$$

$FC_{i,t}$ is the fuel cost (applicable only for natural gas, coal, nuclear, and biomass generators). $FuelPrice_i$ and $HeatValue_i$ are the price and heating value of the fuel used by generator i. $HeatRate_i$ is the rate of electricity output given a unit of fuel input, and could be modeled as a function (linear or non-linear) depending on the generation level. $Generation_{i,t}$ is the instantaneous electricity production from generator i in hour t. It is the main decision variable of the optimization and depends on the unit commitment (integer) decision variable that determines whether the generator is on or off in the particular hour, and also how much of a generator's capacity is set aside to provide reserves.

$$O\&M_{i,t} = Generation_{i,t} * VO\&M_i$$

$O\&M_{i,t}$ is the cost for operations and maintenance for each generator, based on its variable $VO\&M_i$ cost per unit of $Generation_{i,t}$.

$$SC_{i,t} = StartCost_i \times UnitsStarted_{i,t} + ShutdownCost_i \times UnitsShutdown_{i,t}$$

$SC_{i,t}$ is the cost to start and shutdown a generator and is typically applicable only for thermal generators depending on the number of $UnitsStarted_{i,t}$ or $UnitsShutdown_{i,t}$ during the period, which are integer values that are part of the unit commitment decision. $VoLL * UnservedEnergy_t$ is the cost of load shedding. The $VoLL$ sets a maximum price above which there is $UnservedEnergy_t$. If there is not enough generation to meet load, the market price will reach the $VoLL.PriceofDumpEnergy * DumpEnergy_t$ sets a $PriceofDumpEnergy$ below which generators shutoff rather than $DumpEnergy_t$ or over-generate. If there is more generation than load, the market price reaches the $PriceofDumpEnergy$.

Generator unit commitment and dispatch is subject to the following selected constraints:

1) Energy balance constraint. For each utility zone there is an energy balance constraint such that total generation (minus any over-generation) must match the $Load_t$, the total electricity demanded in hour t (minus any under-generation):

$$\sum_i Generation_{i,t} - DumpEnergy_t = Load_t - UnservedEnergy_t$$

2) Power capacity constraint. Instantaneous power output from any generator must be less than or equal to its max capacity:

$$MaxCapacity_i \geq Generation_{i,t}$$

3) Ramping capability constraint. All thermal generators' power ramping has limits:

$$\left|Generation_{i,t} - Generation_{i,t-1}\right| \leq RampRate_i$$

4) Hydropower generators have monthly energy budgets (based on the amount of water they can allocate that month) as well as minimum and maximum flows. PLEXOS first optimizes for the monthly budget through a monthly scheduling process.

5) Unit status exclusiveness constraint:

$$UnitOn_{i,t} = UnitOn_{i,t-1} + UnitStarted_{i,t} - UnitShutdown_{i,t}$$

6) Minimum up/down time constraint. These constraints are specific to the unit commitment problem for minimum stable levels, minimum up time, and minimum down time:

$$Generation_{i,t} \geq UnitOn_{i,t} * MinStableLevel_i$$

When a generator is committed ($UnitOn_{i,t} = 1$), it must operate at or above its $MinStableLevel_i$. $MinUpTime_i$ is the minimum number of hours a generator unit must be on if committed (primarily applies to thermal generators). $MinDownTime_i$ is the minimum number of hours a generator unit must be off if shut down (primarily applies to thermal generators).

7) DC power flow constraint. We enforce a linearized DC power flow that follows Kirchhoff's Voltage Law (the sum of voltages around a loop equal 0), and flows between provinces j and k must not exceed $LineLimits_{jk}$. In the absence of any publicly available data on AC power flow studies or available transfer capabilities between provinces, we have taken *LineLimits* to be the installed transmission capacity between the provinces. This assumption would likely overestimate the actual power transfer capability of the lines in an AC network. Therefore, we run a sensitivity analysis case by reducing *LineLimits* to 50% of the installed transmission capacities between provinces.

Overall, the optimization is a mixed integer program of a unit commitment decision (1 or 0 whether a generator is on or off) and an economic dispatch decision (how much a generator generates).

To solve this program, we apply the mixed-integer programming (MIP) technique. We set the MIP integer gap, the percentage difference between the best integer solution and the best bound (through the Branch & Bound algorithm), to be 0.5%.

Scenario settings

This section provides more details regarding the scenarios that we define in the study.

1) Business-As-Usual scenario (BAU)

The BAU scenario assumes the continuation of current policies and moderate cost decreases in future renewable costs, which serves as a base case in our study. Under the BAU scenario, we choose using the most prevalent system parameters including cost assumptions under the existing energy policy. For example, we assume that capital costs in 2030 are lower than in 2015 by 26%, 31%, and 6% for solar, storage, and wind technologies, respectively. This means that the BAU scenario represents the future portfolio if the China government sticks to the current policies. Second, a low-cost renewables scenario (RE) assumes the rapid decrease in costs for renewables and storage will continue. Third, a carbon constraints scenario (C50) caps carbon at 50% lower than the 2015 level by 2030. Fourth, a deep carbon constraints scenario (C80) further constrains the carbon emissions from the power sector to be 80% lower than the 2015 level by 2030

2) Low-cost Renewable scenario (RE)

Built upon the BAU scenario, the RE scenario assumes the rapid decrease in costs for renewables and storage will continue. Under such a low-cost assumption, 2030 capital costs for solar, storage and wind, are lower than 2015 costs by 80%, 57%, and 66%, respectively, which throws a more generous and realistic incentive of deploying renewables. Technology adoption, learning-by-doing, economies of scale, and manufacturing localization are driving the cost decease of wind technology, and similar effect could be found in the innovation and cost decease of solar PV, and storage. We also retrieve information for the onshore wind and battery storage capital costs by the 2018 NREL Annual Technology Baseline study (NREL, 2018).

3) Low carbon constraint scenario (C50) and High carbon constraint scenario (C80)

Built upon the RE scenario, which means they also enjoys the low-cost renewable energy, the C50 scenario and C80 scenario further cap the carbon emission at 50% and 80% lower than the 2015 level by 2030, respectively.

We detail the reasoning of these four scenarios as follows. On the one hand, in recent years, the renewable and storage investment costs are drastically decreasing than anticipated. Thus, the RE scenario is designed comparing with the BAU scenario to capture this trend. On the other hand, the China's carbon neutrality goal is set for 2060, which drives us to consider the aggressive carbon emission mitigation goals in the C50 and C80 scenarios. We also compare these two scenarios to conduct quantitative assessments on the carbon emission reduction brought by a better economy-driven portfolio.

Building upon these four renewable energy penetration scenarios (BAU, RE, C50, C80), we examine different grid operation and dispatch strategies for three factors: coal power-plant flexibility, balancing area, and transmission constraints. For a better readability, we include the literal code used throughout the figures in parentheses for all the designed cases.

For coal flexibility (CoalFlex), we compare a baseline case with a flexible coal plant operation case. The technical minimum generation level is assumed to be 25% of rated capacity (Flex25) compared with 50% in the base case (Base). The ramping capability is assumed to be 2% per minute compared with 1% per minute in the base case.

For balancing areas (Balancing), we define three cases to compare the effect of enlarging balancing areas: provincial balancing (Provincial), regional balancing (Regional), and national balancing (National). To realize different balancing strategies, we impose transmission hurdle rates between the scopes of nodal power delivery in our model. For more details regarding how balancing strategies are implemented in reality, we refer to Kahrl et al. (2013) and Kahrl et al. (2015) (Kahrl et al., 2013; Kahrl and Wang, 2015). Note that the term regional balancing used in this paper refers to regional grid balancing. China's current dispatch practice is closest to a provincial balancing, but not exactly.

For transmission constraints (Tx_Inv), we consider economic hurdles to building new transmission capacity, which would encourage more geographically dispersed renewable investment. We assume one case with 300 USD/MW-km investment cost for new transmission lines (300) and second case with 1000 USD/MW-km investment cost (1000). Note that these parameters are used to run the capacity expansion planning while more expensive transmission investment generally implies a more dispersed renewable energy buildout.

The combined total scenarios add up to 48.

Next, we provide further details regarding cost assumptions and settings used in these scenarios and cases.

For capital cost, which are amortized over the expected lifetime of each generator or transmission line, only capital payments that occur during the period covered by the study are included in the objective function. Modeled capital costs for coal, gas, hydro, and nuclear plants include trends to 2030 for different sizes and technologies of these plants. 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. For renewable units, we use 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 RE, C50, and C80 scenarios assume that lower costs for storage, solar, and wind power technologies are expected.

For fuel cost, average national fuel costs for coal and gas in 2017 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.

For operation and maintenance (O&M) costs, we use operation and maintenance costs in addition to capital and fuel costs to calculate total system costs over a period of time. 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.

QUANTIFICATION AND STATISTICAL ANALYSIS

There is no quantification and statistical analysis conducted in this paper.