International Energy Analysis Department
Energy Analysis and Environmental Impacts Division
Lawrence Berkeley National Laboratory

Enhancing grid flexibility under scenarios of a renewable-dominant power system in China

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

*both authors contributed equally to this analysis
[1]Stony Brook University , [2] Peking University

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Jiahai Yuan	North China Electric Power University, China

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1. Introduction

The Chinese power sector is among the world's top emitters, accounting for about 14% of global energy-related carbon emissions.[1] 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. [2]

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.[3] While 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.[4,5] 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.

2. Literature Review

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: [6–8] transmission,[9] larger balancing area, storage,[10] demand response, power system operation, electricity market, and integrating supply-load transmissions.[11] Cochran (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.[8,12] Batteries and other energy storage resources, especially long-duration energy storage, also become crucial at higher levels of penetration.[10,13] Demand response could be used in enhancing grid flexibility, offering a viable, cost-effective alternative to supply-side investments.[14–16] 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,[17] and to align with other market instruments such as emission trading systems (ETS).[18]

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- and demand-side options, including flexible conventional generation, grid storage, new transmission, more responsive loads, and changes in power system operations.[19–21] A more recent study shows reaching 90% carbon-free electricity by 2035 is possible due to plummeting solar, wind, and storage costs.[22] 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.[23,24] Deshmukh (2021) and Abhyankar (2021) 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%.[25]

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.[4] 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. 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.[26] Ding et al. (2021) use Jiangsu as an example and show that retrofitting coal units to meet peak load could improve system flexibility.[27] Lin et al. (2019) and Abhyankar et al. (2020) study the benefits of economic dispatch and electricity markets in Guangdong and the Southern Grid.[28,29] 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.

3. Methods and Data

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).

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.

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 coal flexibility, 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. The ramping capability is assumed to be 2% per minute compared with 1% per minute in the base case.

For balancing areas, we define three cases to compare the effect of enlarging balancing areas: provincial balancing, regional balancing, and national balancing. China's current dispatch practice is closest to a provincial balancing, but not exactly.

For transmission constraints, we consider economic hurdles to building new transmission capacity, which would encourage more dispersed renewable investment. We assume one case with no transmission hurdle rate and second case with 1000 USD/MW-km investment cost for new transmission lines. The combined total scenarios add up to 48.

We also apply cost assumptions in our analyses, which can be found in Appendix A.

4. 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.

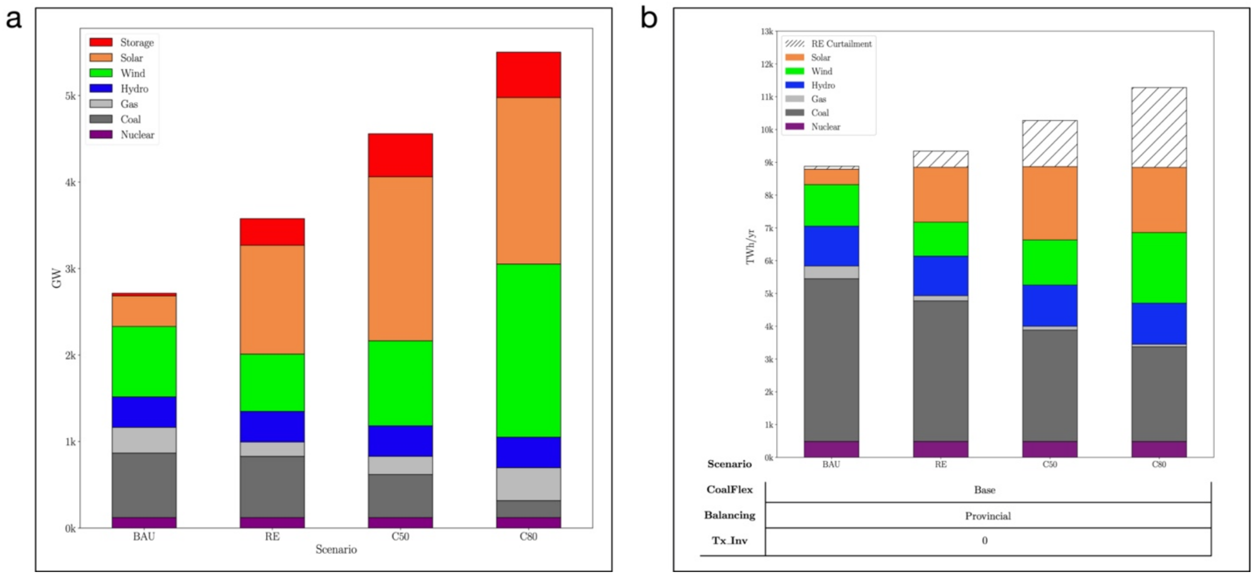

Figure 1. Installed capacity and generation by technology in 2030 under different carbon-mitigation scenarios (1a) and with the current provincial balancing (1b)

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 due to lower seasonal demand (Figure 2b).

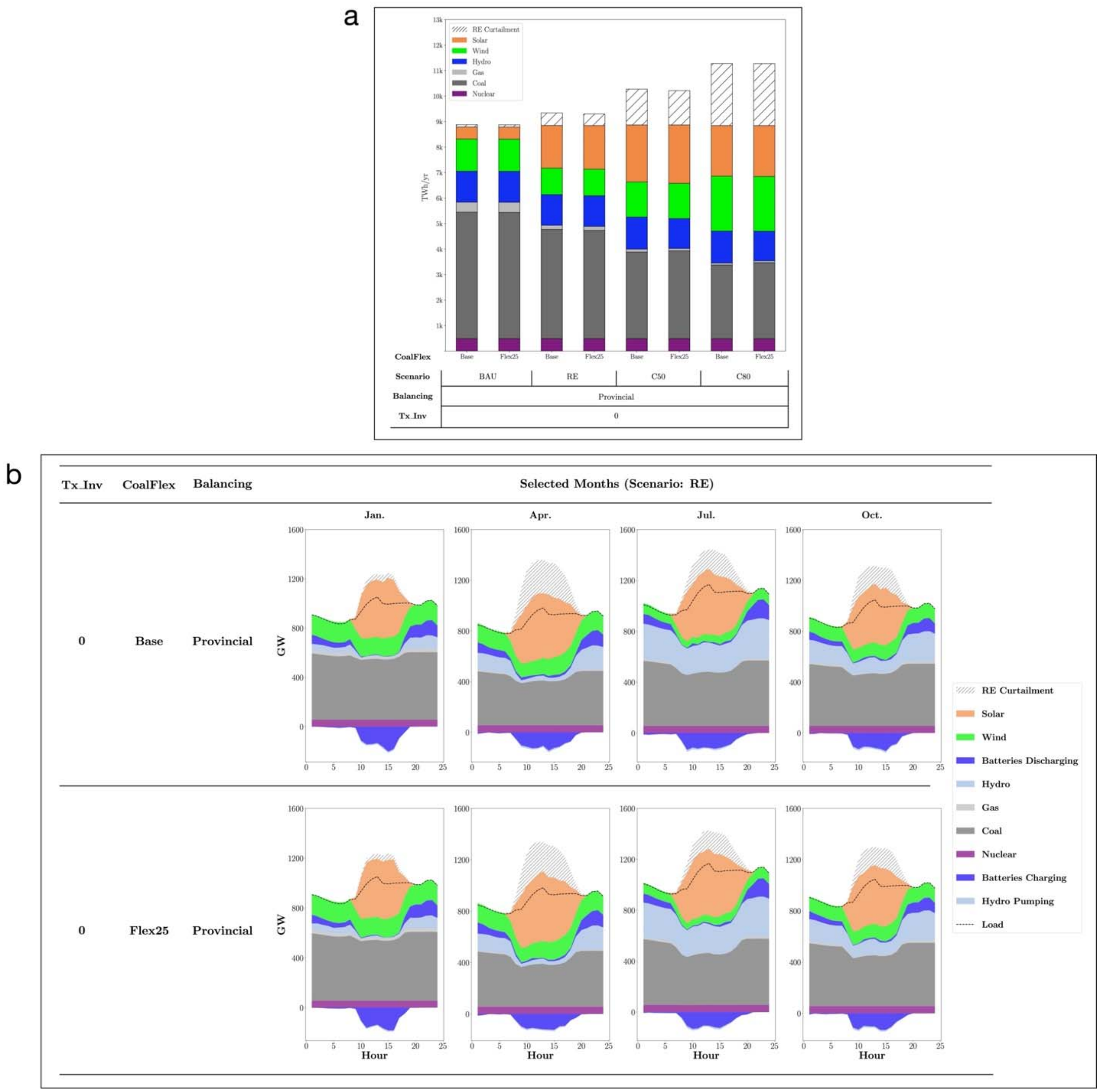

Figure 2. China national annual power generation by technology with two levels of coal flexibility under four renewable energy scenarios (2a) and average national dispatch with twos level of coal flexibility under the RE scenario (2b)

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, 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.

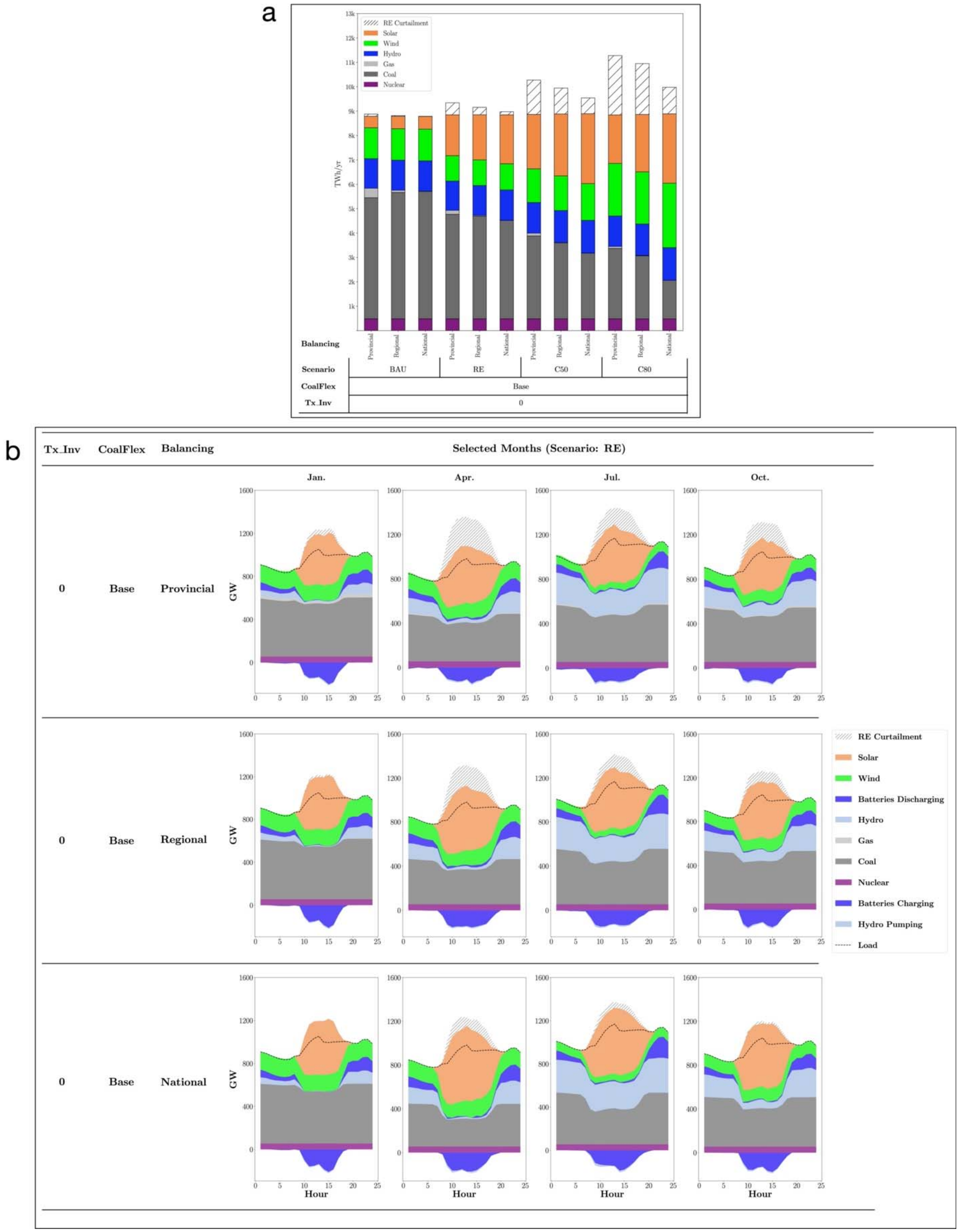

Figure 3. China national annual generation (all scenarios) (3a) and average dispatch in typical months (RE scenario) with provincial, regional, and national balancing (3b)

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 a no and a high transmission hurdle rate, which would encourage more local renewable investment. As shown in Figure 4, renewable curtailment and coal generation drop in all scenarios with a 1000 USD/MW-km transmission hurdle rate. This result demonstrates that investing in renewable energy in a more distributed 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 hurdle rate compared with no transmission hurdle rate. These benefits are comparable with establishing regional balancing areas.

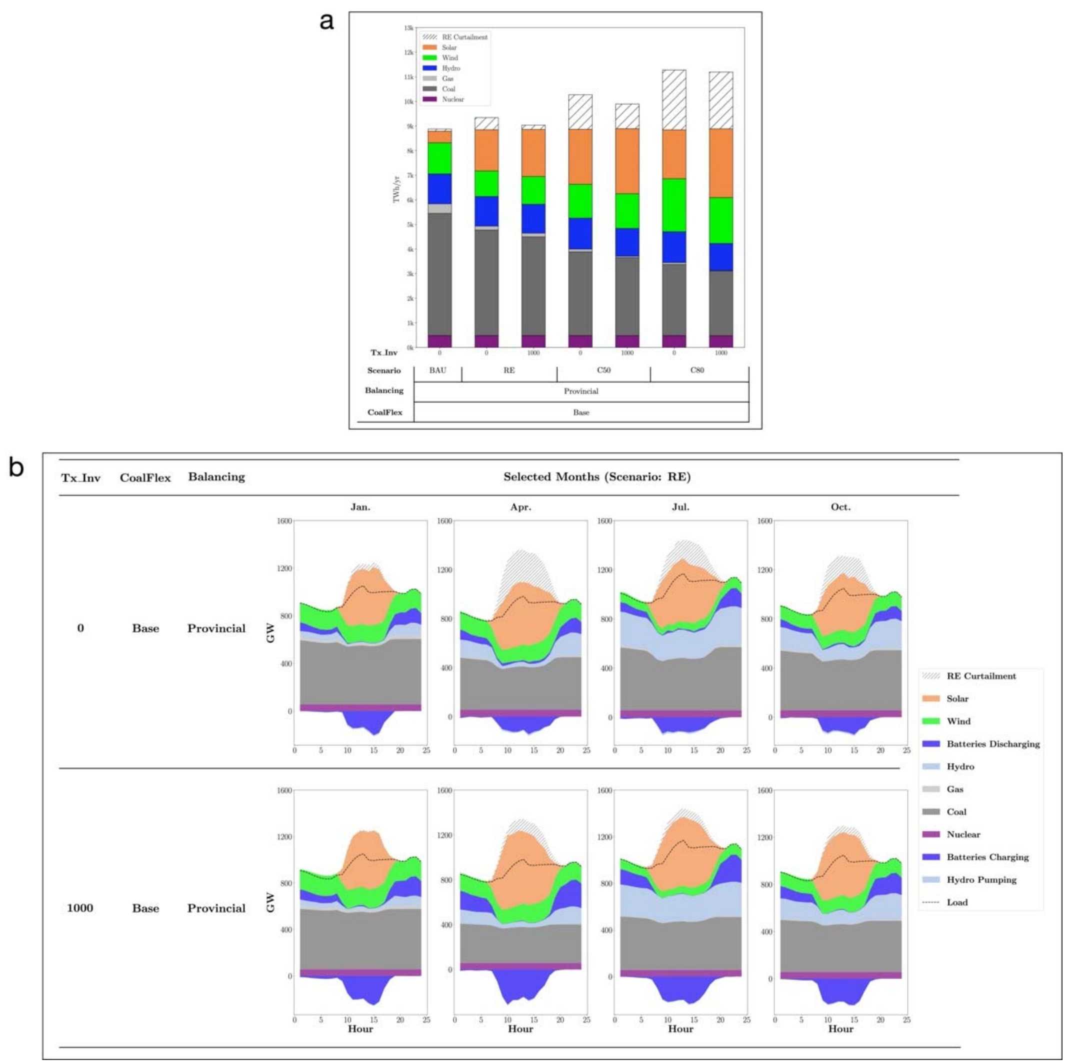

Figure 4. China national annual generation (4a) and average dispatch (RE scenario) with no transmission hurdle rate compared with a 1000 USD/MW-km transmission hurdle rate (4b) under provincial balancing

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%, 26% under RE, C50 and C80 scenarios (compared with 15%, 28%, 37% with provincial balancing and less distributed renewable investment), respectively, while 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, C50, and C80 scenarios, respectively.

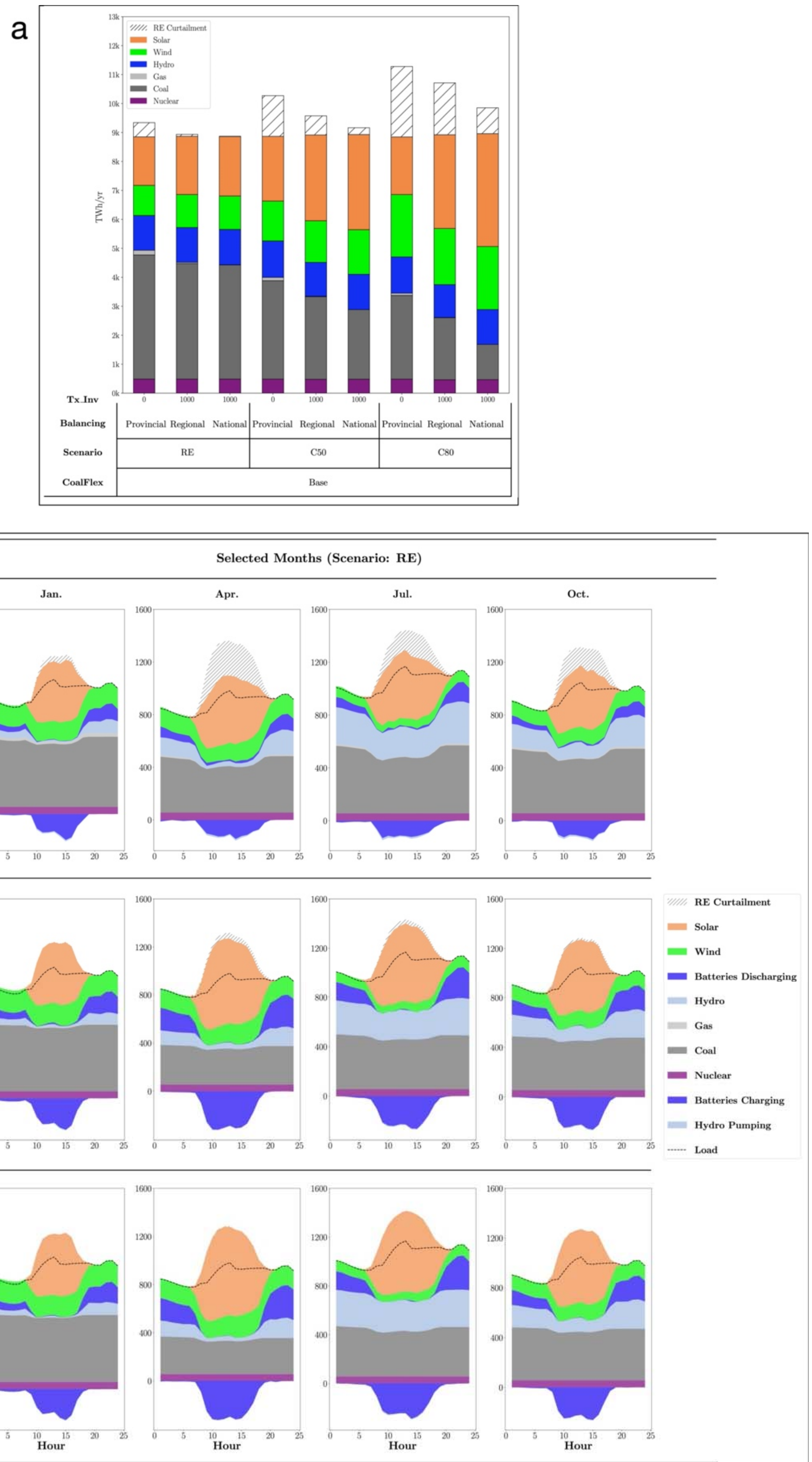

Figure 5. China national annual generation (all scenarios) (5a) and average dispatch (RE scenario) with no transmission hurdle rate with provincial balancing area compared with a 1000 USD/MW-km transmission line investment constraint (5b) with larger balancing areas

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 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.

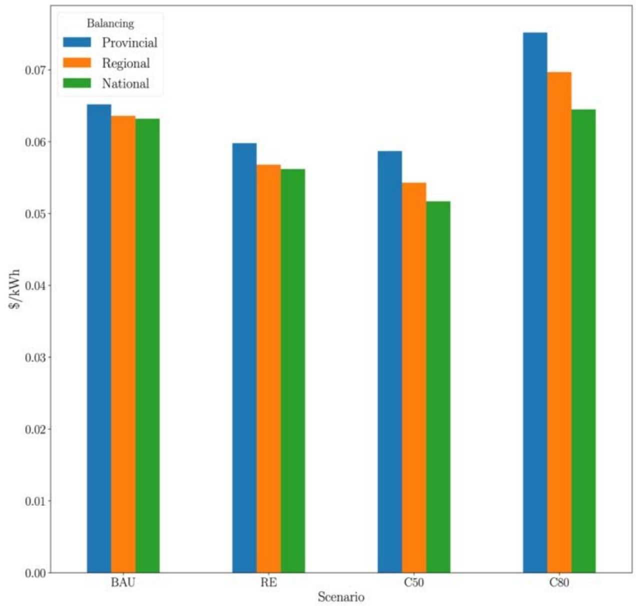

Figure 6. Average wholesale cost of electricity (fixed costs included) under different scenarios

5. 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 flexibility, renewable integration, and system reliability, primarily because there is already a large amount of excess coal power 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.

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 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.

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Appendix A. Cost Assumptions

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.

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 RE 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. 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. The onshore wind and battery storage capital costs are informed by the 2018 NREL Annual Technology Baseline study.

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.

Readers could refer to He et. al (2020)[2] for more details regarding the cost settings in our study