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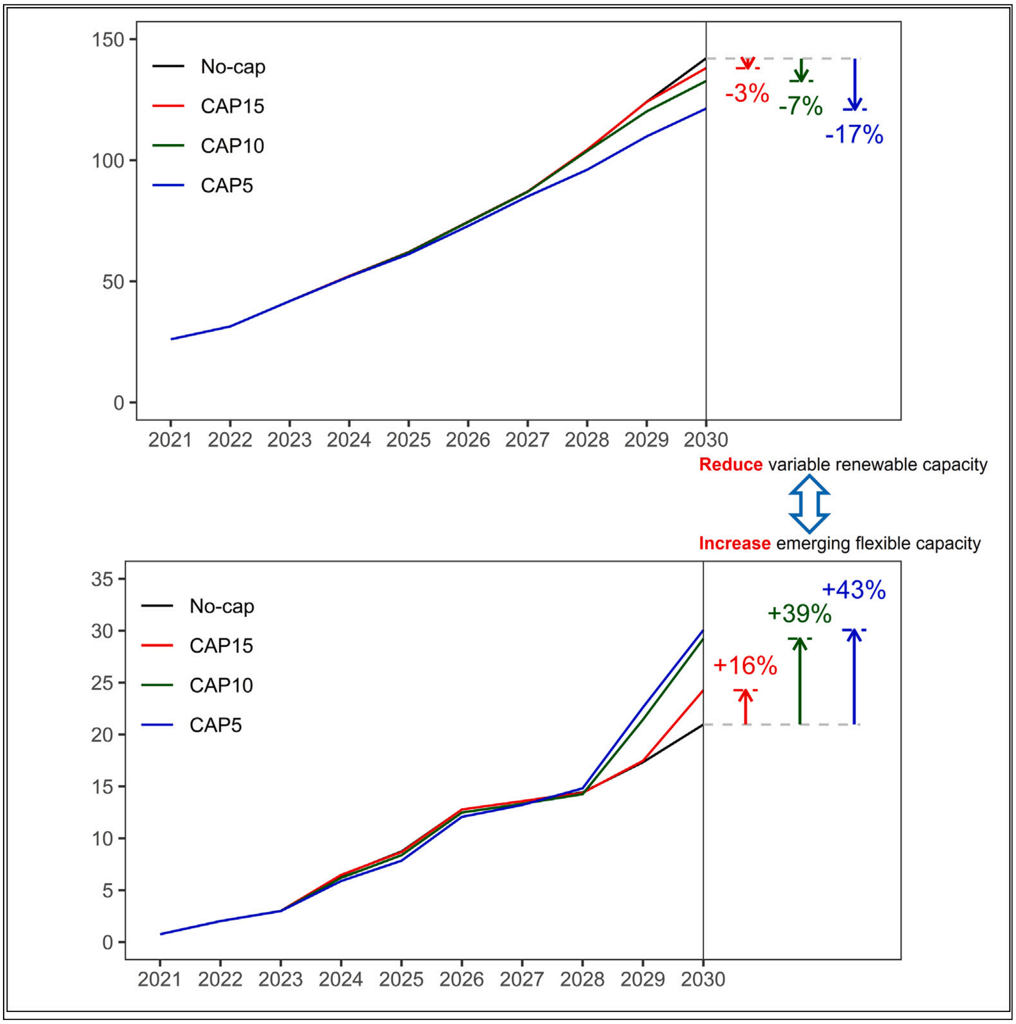
Unintended consequences of curtailment cap policies on power system decarbonization



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Highlights

Capping curtailment increases costs and emissions and jeopardizes reliability

Capping curtailment reduces renewable capacity and increases flexible resource capacity

Capping curtailment increases fossil fuel utilization and reduces hydro utilization

Policymakers must think carefully about the unintended effects of curtailment caps

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Unintended consequences of curtailment cap policies on power system decarbonization

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SUMMARY

As countries pursue power system decarbonization, a well-intentioned strategy being pursued in jurisdictions like China is the strict integration target, often in the form of a curtailment cap. The effects of these curtailment caps have not been systematically studied. Here, we evaluate the effects of these caps on the decarbonization of one provincial power system using a capacity expansion model. Results reveal that curtailment caps yield deleterious effects that do not align with the stated goals of these policies. Capping curtailment significantly increases storage capacity (+43% with a 5% curtailment cap) and reduces renewable capacity (−17%). Even with the increase in flexible storage capacity, the policy still jeopardizes power system reliability by increasing occurrences of over or under generation. It also suppresses power generation from hydropower and reduces energy storage utilization while increasing fossil fuel utilization. Capping curtailment increases economic costs (+6% with a 5% curtailment cap) and CO_2 emissions (+7%).

INTRODUCTION

Deploying larger amounts of variable renewable energy (VRE) is an essential component of efforts to reduce greenhouse gas (GHG) emissions from the global energy system.[1–4] Among these technologies, wind and solar have become mature and economically competitive electric power generation options,[5–11] although their variability and intermittency continue to pose a challenge to investors, markets, system operators, and policy makers as they seek the appropriate mix of strategies to expand development.[12–16]

Thus far, accommodating VRE sources has involved experimentation among stakeholders. Most jurisdictions accept that not all generation by VRE sources can currently be integrated into the power system—some energy is curtailed or spilled.[17,18] Going forward, there are proposals for multiple technological and policy levers that could be actuated to enhance renewable energy integration and reduce such curtailment.[19] One technological solution is to deploy flexible and dispatchable low-carbon sources of power generation.[20] Power systems with such flexible sources might be able to cope with the variability and intermittency of VRE sources; less flexible systems might yield greater renewable energy curtailment.[21,22] Policy instruments can also serve to either incentivize or mandate renewable integration. For example, markets could provide incentives for integration[23,24]; policy makers could mandate that all renewable generation be integrated into the grid[25]; or system operators and policy makers can suggest binding "curtailment caps" — modest percentages of renewable energy production that are allowed to be spilled to ensure the reliable and cost-effective operation of the power system.[26,27]

China provides fertile ground for such experimentation, given the scale of its energy transition, its ambitious climate targets, and the sheer diversity in power systems across its jurisdiction.[28–31] This is evidenced by the fact that its provinces are pursuing curtailment caps and other solutions to boost renewable integration. In this article, we focus on one policy lever—curtailment cap policies—and evaluate how their implementation is likely to impact the power system's generation mix, reliability, cost, and emissions. We do this because, although many renewable integration policies are well-intentioned and appear wise, it is only through careful and systematic analysis that we can shed light on their benefits and risks. Our research allows system operators and policy makers to anticipate the likely future impacts of their curtailment cap policies and course-correct, if necessary.

We focus on the curtailment cap policy because China has been actively pursuing it: to promote VRE integration, the Chinese government set a 5% cap on the curtailment ratios of wind and solar power in 2020.[32]

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Table 1. Four scenarios cap renewable energy curtailment at different levels, enabling assessments of the benefits and risks of this popular policy

Scenario	Curtailment cap	Constant across scenarios	Variable across scenarios
No-cap	None	- Future demand	- Capacity expansion of wind, solar PV, BESS, CSP
CAP15	15%	- Existing energy infrastructure	- Operation of existing and new infrastructure
CAP10	10%	- Capacity plans for coal, natural gas, hydro, PHS	
CAP5	5%		

The curtailment ratio is calculated as the total curtailed electricity from solar and wind over the total generation from solar and wind. It is usually calculated every year. In a sign that curtailment caps are here to stay, the Chinese government has mandated that newly added VRE capacity be equipped with energy storage facilities. To satisfy this directive from central government, local governments have set various storage deployment requirements.[33] The VRE curtailment cap policy is designed to promote VRE development by guaranteeing expected returns to investors in VRE capacity. The feed-in-tariff policy guarantees the price and the curtailment cap policy guarantees the volume, leading to a relatively stable financial return. By reducing curtailment from marginal-cost generators, it is hoped that greater profits will accrue to investors and thus stimulate further investment in VRE capacity. This curtailment cap policy, in combination with others such as the subsidy for integrated wind and solar, has played an important role in VRE deployment in China.[34,35]

This policy is being pursued even though the lack of flexibility in China's power system is likely to become more pronounced.[36] Flexibility is loosely defined as the ability to change generation in a certain period of time. Coal power is China's primary electricity source[37–39] and retrofitting coal units could provide a great deal of flexibility[23,40] but, given China's ambitions to achieve peak CO_2 emissions before 2030 and carbon neutrality before 2060,[41] coal units will be gradually phased out,[42–45] making flexibility even scarcer in the power system.[46] China plans to significantly expand its pumped hydro storage (PHS) capacity,[37] but these projects take a long time to be approved and constructed.[47,48] Options to improve the flexibility of China's electric power system are limited in the short term;[49] despite this challenge, China is significantly and concurrently expanding its VRE capacity.[50] In recent years, new VRE capacity has accounted for the most of China's new added capacity, and this trend is expected to continue.[51]

This paper is the first to analyze the impact of this curtailment cap policy on the Chinese power system. More broadly, it sheds light on how curtailment cap policies should be viewed by system operators and policy makers: should policy makers abandon these policies, overbuild VRE resources, and spill generation that cannot be integrated into the power system?[47] Or, should they adopt curtailment caps and mandate flexible low-carbon generation, including through technologies like battery energy storage systems (BESS)? To what extent would this make the power system costly and distort the optimal resource mix? Extensive studies have evaluated the role and value of BESS in the decarbonization of energy systems.[52,53] These studies have found that the deployment of flexible technologies is beneficial in supplementing energy systems with high VRE penetration, reducing economic costsand GHG emissions and enhancing power system reliability. However, the value of these flexible technologies could be affected by curtailment cap policies. As countries pursue radical technological and policy solutions to accelerate their transition to decarbonized power systems, our results yield counterintuitive and timely policy implications for system planners and operators, policy makers, and investors who are keen on minimizing the level of disruption in the net-zero transition.

We optimize and simulate capacity expansion planning and power system operations in the Chinese province of Qinghai from 2021 to 2030. We analyze capacity expansion and power system operations in scenarios with and without curtailment cap policies. A scenario without a curtailment cap policy allows us to understand how the resource mix and VRE curtailment ratio evolve over the decade under investigation and as power system decarbonization proceeds. By comparing this ''no-cap'' scenario with three others that cap curtailment at different levels, we can quantitatively and comparatively assess the implications that curtailment cap policies have on the energy mix, cost, power system reliability, and emissions. These scenarios are summarized in Table 1. By formulating the analysis this way, we can answer challenging questions like whether higher integration or higher curtailment is more prudent as VRE penetration increases;

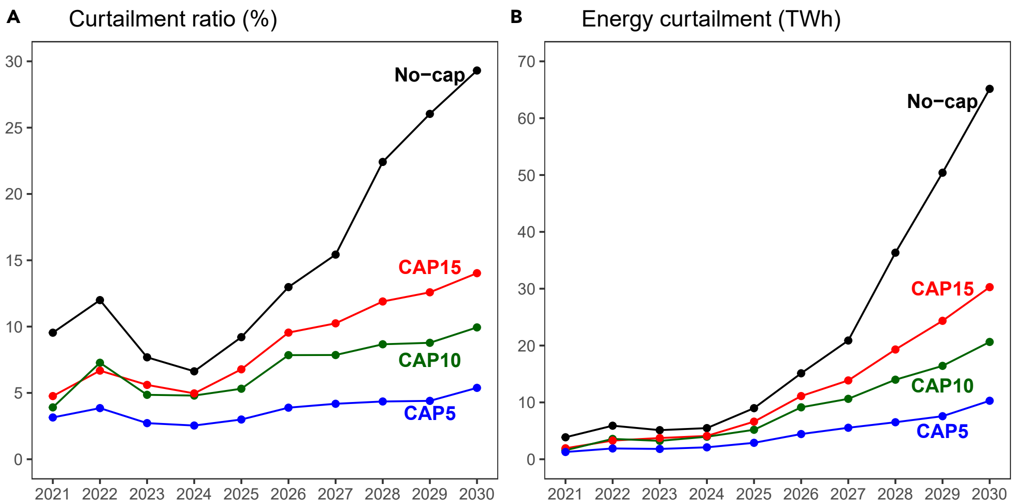

Figure 1. Changes in VRE curtailment during 2021–2030 under different curtailment cap scenarios

(A) VRE curtailment ratio during 2021–2030. The curtailment ratio is the curtailed electricity from solar and wind divided by the total generation from solar and wind.

(B) Curtailed electricity from solar and wind during 2021–2030.

whether the power system needs additional storage and how much is reasonable; and what curtailment cap policies actually cost, both economically and in terms of GHG emissions.

In the following section, we present our results, outlining the impacts of different policies on the power system's resource mix, resource utilization, costs, reliability, and emissions. We conclude by recapitulating key take-away messages and the implications of our results for system operators and policy makers.

RESULTS

Curtailment cap policies yield significant technical, economic, and environmental consequences for the power system. Below, we discuss each of these in turn.

Expectedly, as the penetration of VRE sources increases dramatically in response to deep decarbonization targets, curtailment ratios increase as well. When there is no curtailment cap policy in place, curtailment levels soar, hitting almost 30% in 2030. If stringent curtailment caps are in place, those caps are hit by the year 2030 (Figure 1). These results yield three insights for investors, power system planners, and policy makers. First, if a curtailment cap is imposed, power systems with high VRE penetrations will end up meeting that cap to prevent further investment in flexible low-carbon generation. This might seem intuitive, but it means that system planners must be very careful in considering the planning horizon that is informing their curtailment cap if they do not want to depress medium to long-term investments in VRE sources. Second, we find that curtailment is mainly driven by solar PV: its curtailment rates are almost twice as high as wind curtailment rates in 2030. This resource simply does not fit the demand profile of Qinghai province (or any other power system of which we are aware). Policy makers and power system planners must therefore prioritize (or mandate) investments in resources that complement solar PV generation to mitigate its curtailment. Third, the curtailment challenge is persistent, and one-off curtailment caps will not fix the issue. Going forward, power system operators and policy makers must establish and iteratively refine policies that strike a balance between reducing curtailment (thus benefiting VRE investors and encouraging further investments in low-carbon resources) and ensuring power system reliability.

Curtailment cap policies also have enormous effects on a power system's capacity expansion, energy mix, and resource utilization. When a curtailment cap is imposed, curtailment ratios cannot be reduced cost-effectively, so investment in renewable resources is restricted instead. As the curtailment cap becomes more stringent, the installed capacity of VRE resources falls and the installed capacity of flexible resources like BESS rises.

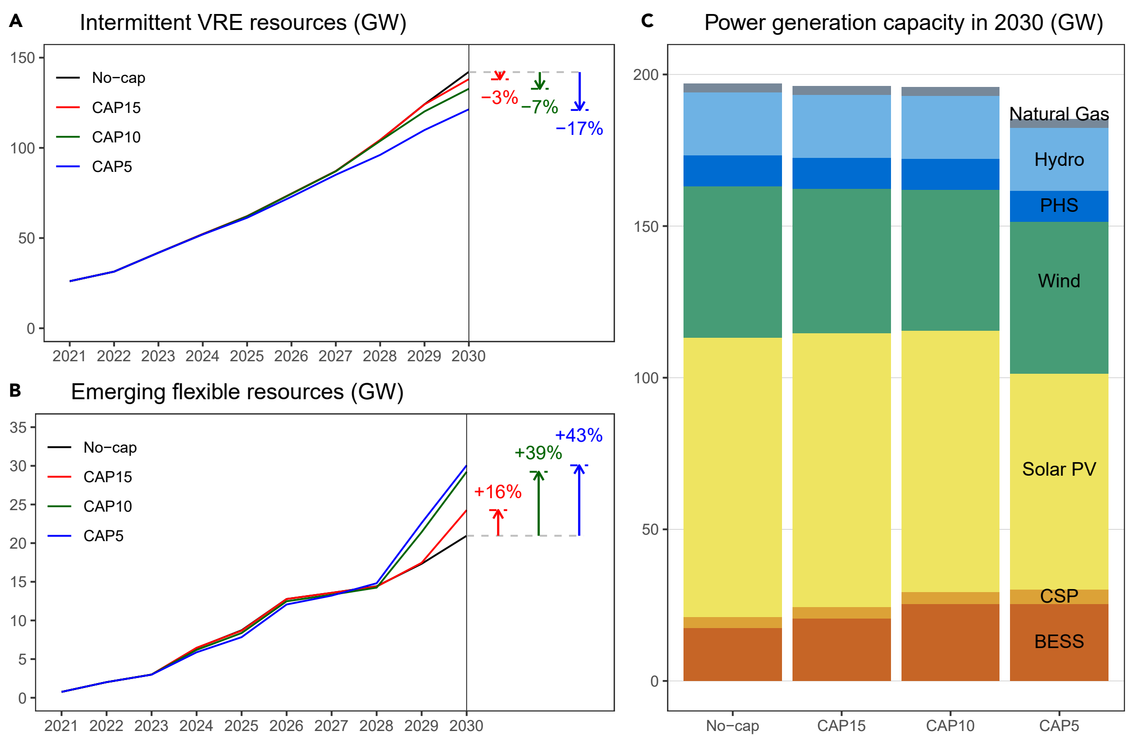

Figure 2. Capacity expansions under different curtailment cap scenarios

(A) Capacity expansion of intermittent VRE resources (including wind and solar PV) during 2021–2030.

(B) Capacity expansion of emerging flexible resources (including CSP and BESS) during 2021–2030.

(C) Capacity mix of power generation in 2030.

The trend between curtailment cap stringency and installed capacity is not linear, however, as presented in Figure 2A. As the cap becomes more stringent—from 15 to 10% and finally to 5%—the installed capacity of VRE resources falls by 3%, then 7%, then 17% relative to the base scenario with no curtailment cap. The installed capacity of flexible resources, meanwhile, increases by 16%, then 40%, and then 43%, respectively (Figure 2B). Our results reveal that particularly stringent curtailment cap scenarios, like the 5% scenario we model here, achieve this goal by significantly reducing installed VRE capacity and total power generation capacity, and by boosting flexible capacity. System operators and policy makers should be wary of pursuing ultra-low curtailment targets, as these induce the unintended and deleterious effect of reducing VRE expansion at a time when governments are aggressively promoting further renewable development.

Another key insight generated by our analysis is regarding the amount of storage that ought to be deployed to complement renewable capacity. System planners and governments understand that the variability and intermittency of renewable generation needs to be balanced with storage and other flexible resources. In fact, many local governments in China have set requirements in the form of a storage-to-renewable power ratio. Qinghai promulgated a policy in 2021 mandating developers to install storage systems with at least 10% of the power capacity of their renewable generators. Moreover, storage system duration must be at least 2 h. Based on our results, this requirement is reasonable across curtailment cap scenarios until 2024. After 2024, the prudent storage-to-renewable power ratio grows to 20% in the base (no-cap) scenario and 30% when the curtailment cap is an ultra-low 5% (Figure 2C). Policy makers must be highly cognizant of the need to adjust these storage capacity requirements for new renewable generation projects as VRE penetration grows. They must ensure that their responses are nimble and clearly communicated to investors to ensure adequate planning and sufficient storage capacity.

As expected, curtailment cap policies increase the capacity factors of renewable resources (Figure 3). In 2030 and compared to the no-cap scenario, the 5% curtailment cap scenario reduces solar PV curtailment from 36.8 to 7.2% and increases its capacity factor from 10.8% (949 out of 8760 h of a year) to 15.9% (1394 h). The improvement in wind capacity factor in 2030 is smaller, increasing from 15.9% (1394 h) to 18.5% (1626 h)

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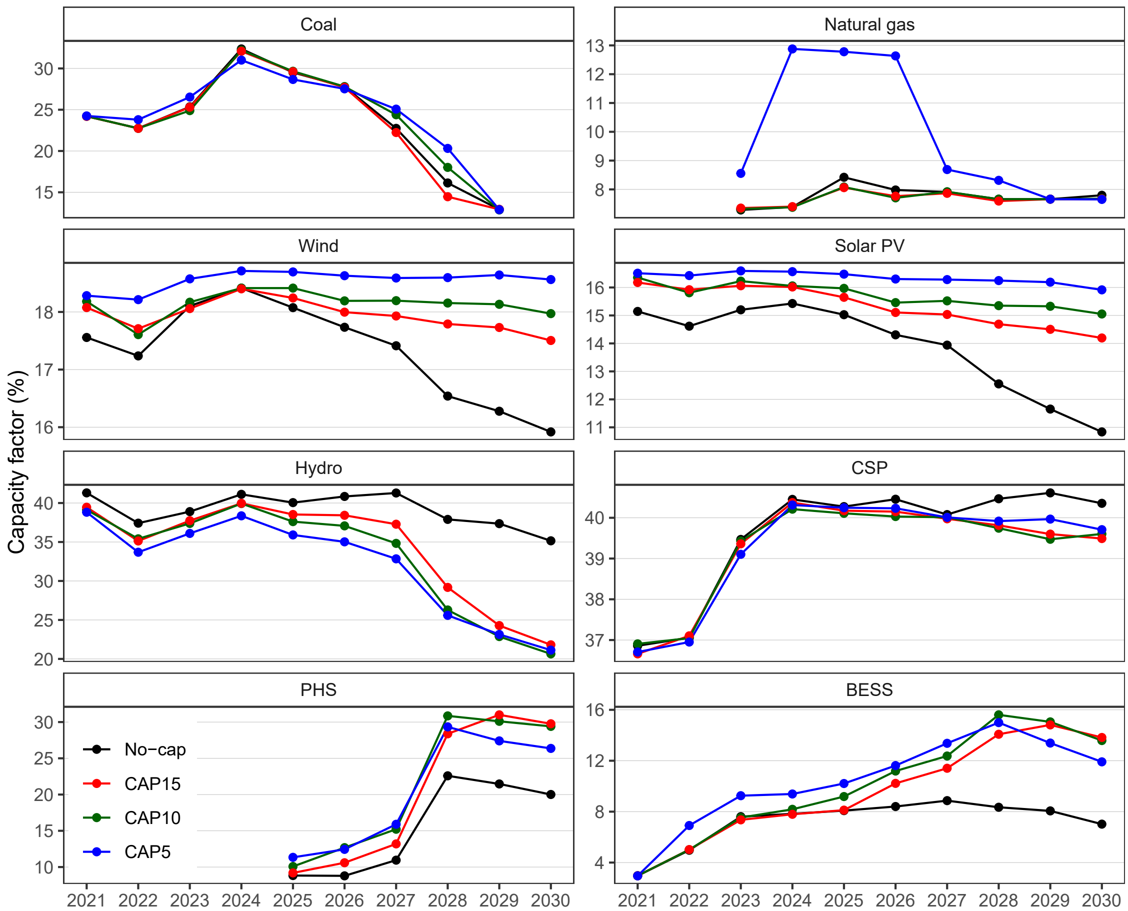

Figure 3. Changes of capacity factor from various sources under different curtailment cap scenarios

Note: the capacity factor of PHS and BESS are the energy discharge at equivalent full power discharge capacity, which is the annual energy discharge divided by the rated discharge power and 8760 h.

when the 5% curtailment cap is imposed. However, the curtailment cap policy does not guarantee that these higher capacity factors for renewable resources will not decline over time—in fact, renewable capacity factors fall over the period from 2021 to 2030 even when strict curtailment cap policies are imposed. Curtailment cap policies are often regarded as a way of guaranteeing returns to investors in renewables, but capacity factors are more accurate measures of renewable profitability when the price is stable, as it would be with a feed-in tariff. Our results suggest that strict curtailment cap policies guarantee significant improvements in capacity factor compared to a no-cap scenario, but even these capacity factors fall over time as penetration grows and integration becomes more difficult.

More interesting is how curtailment cap policies affect power system operation. For example, they suppress generation from hydropower, another clean generation resource. The role of hydropower shifts to that more traditionally associated with peaker plants: it provides flexibility rather than electricity. This suppression of hydropower generation occurs across scenarios with curtailment cap policies, and all scenarios with curtailment cap policies have similar hydropower capacity factors in 2030 — all much lower (around 20%) than the capacity factor in the no-cap scenario (almost 40%). It is ironic that a policy aimed at promoting renewable resource utilization depresses the utilization of hydropower; it is also fundamentally not the intention of this policy, which is aimed at accelerating the move toward a decarbonized energy system.

Energy storage systems—both BESS and PHS—witness an increase in their capacity factors when a curtailment cap policy is imposed, but only up to a point. When the curtailment cap is most stringent (5%), storage system utilization decreases. This is primarily because of the reduction in installed capacity of renewables, and not because of an increase in installed capacity of flexible resources, as evidenced by Figure 2B. From

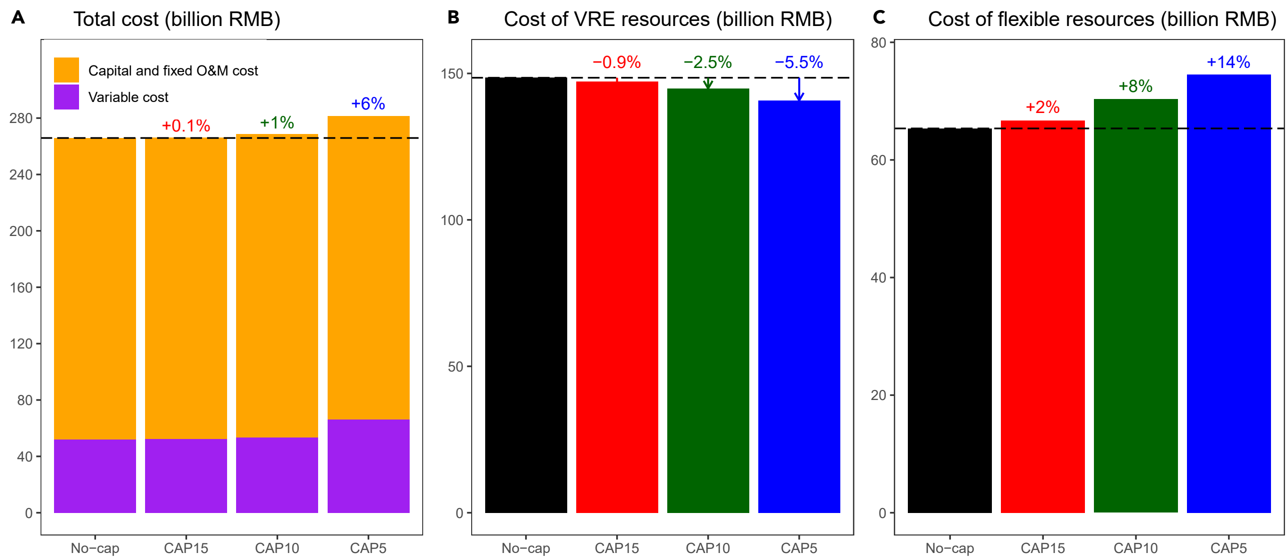

Figure 4. Comparison of power system costs during 2021–2030 in Qinghai

(A) Total power system costs.

(B) Capital and fixed O&M cost of new VRE resources (including wind and solar PV).

(C) Capital and fixed O&M cost of new flexible resources (including CSP and BESS).

the perspective of investors, strict curtailment policies are usually considered positive market signals, because they indicate that the grid needs more energy storage. Our results suggest that a strict curtailment cap policy would reduce the utilization of energy storage, unlike what conventional wisdom might suggest.

Fossil fuel power units, which can also provide some flexibility, benefit from the curtailment cap policy, leading to higher capacity factors when renewable penetration is high. For example, the capacity factor of coal in 2028 in the CAP5 scenario is 20% higher than its capacity factor in the no-cap scenario. Equally troubling for a policy that seeks to accelerate decarbonization is the significantly higher utilization rate of natural gas units in the CAP5 scenario. Although the system waits for substantial amounts of battery capacity to come online, natural gas is forced to provide flexibility for the system.

As for the economic impacts of curtailment cap policies, Figure 4A presents the total power system cost over the planning period (2021–2030) for all four scenarios. Capping curtailment results in increased cost to the power system. When the curtailment ratio is capped at 5%, the total cost increases by 6% compared to the no-cap scenario. This translates to 15.7 billion RMB. The increased cost in the 10% curtailment cap scenario is 2.6 billion RMB (1% higher than the no-cap scenario), and for the 15% curtailment cap scenario it is 0.23 billion RMB (0.1% higher than the cost of the no-cap scenario). These additional costs are because of the increase in installed capacity and dispatch of more flexible (and more expensive) resources, including more frequent start-ups, as well as the penalty from both over and under generation. These costs are offset by the reduction in VRE deployment, though these resources are relatively cheaper to build and operate. In the 5% curtailment cap scenario, the capital costs do not increase much (they are only 0.7% higher than in the no-cap scenario), because the increased investment in flexible resources is partially offset by reduced investment in renewables (Figures 4B and 4C). The operating cost of the power supply system, however, increases from 18.4 billion to 21.2 billion RMB, a 15% increase on the no-cap scenario. Again, this is mainly because of the costs of more frequent start-up, and variable costs of power generation from fossil fuel units.

Another major driver of the cost increase is the system-wide penalty imposed by operators for over or under generation. This penalty is 34% higher (11.5 billion RMB) in CAP5 than it is in the no-cap scenario. The penalty from under or over generation reflects the operational reliability of power system. As shown in Figure 5, when the curtailment cap policy become stricter, both under and over generation increase, with over generation increasing more. Increased under or over generation can be interpreted as a threat to grid reliability, though the penalty for over generation could also be interpreted as a penalty on curtailment. If the curtailment cap policy is not formulated as a "hard" constraint – meaning that it could be violated by

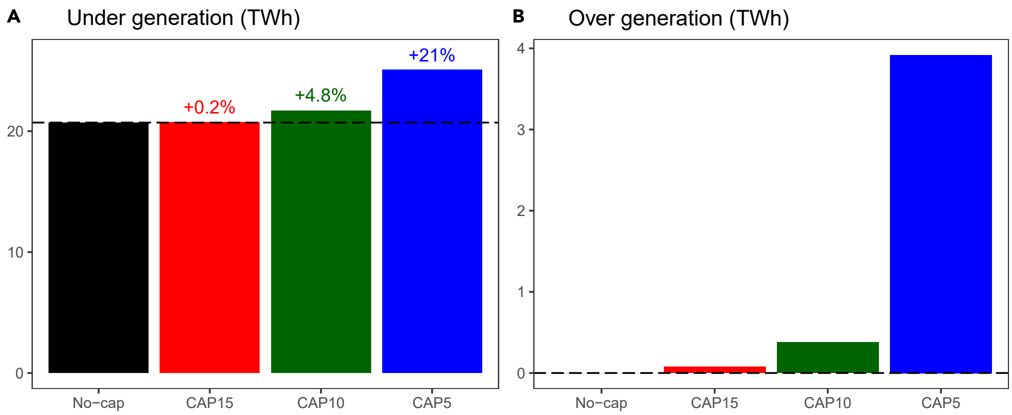

Figure 5. Comparison of power system reliability under different curtailment cap scenarios during 2021–2030 in Qinghai

(A) Under generation.

(B) Over generation.

generators with a penalty imposed – the system will make a trade-off between reliability and curtailment depending on the size of the penalty.

Although curtailment cap policies depress renewable capacity and radically increase the installed capacity of flexible resources – thus boosting the power system's ability to deal with intermittency and variability – they still could potentially jeopardize power system reliability by increasing periods of over or under generation.

The most striking manifestation of the deleterious effect of curtailment cap policies is their effect on GHG emissions. Figure 6A shows that these caps, which are at their broadest designed to promote decarbonization, increase GHG emissions from the power system. As discussed earlier, these curtailment cap policies increase the capacity factor of fossil fuel power units, resulting in higher overall CO_2 emissions. Compared with the no-cap scenario, capping curtailment at 5% results in a 7% rise in CO_2 emissions. Most of these come from coal-fired units, and specifically from start-up emissions (Figures 6B–6D). Coal units provide the power system with the flexibility it needs in the stringent cap scenarios by frequently starting up and shutting down, despite the cost associated with such operation. This is evident in the most stringent cap scenario, CAP5, in which start-up CO_2 emissions triple compared with the baseline, no-cap scenario. This is yet another unintended consequence of stringent curtailment cap policies. A vital justification for such curtailment cap policies is to support renewable energy development on the premise that greater renewable resource utilization would ultimately reduce GHG emissions, helping to mitigate climate change and generating positive externalities. In this case, a stringent version of a policy that is designed to decarbonize the power system ends up increasing GHG emissions instead.

DISCUSSION

One cluster of policy measures to promote the increased development of renewable energy and the integration of renewable electricity is to cap curtailment from VRE sources. This policy cluster comes in many flavors, from promoting transmission expansion or integrated storage to implementing a hard constraint that limits curtailment to a specific percentage of renewable electricity generation. China is experimenting with many of these policies, including hard curtailment caps. It is hoped that these policies might achieve multiple power system objectives at once: importantly, they would reward investors in renewable energy projects, encouraging the development of further renewable capacity. In addition, they would accelerate progress toward decarbonization by boosting renewable resource utilization and mitigating GHG emissions from the power sector.

This study quantitatively evaluates the system-wide impacts of capping curtailment on the transition to a lower-carbon electric power system. Our results show that pursuing renewables integration by capping curtailment yields multiple deleterious effects, raising doubts regarding the wisdom of stringent

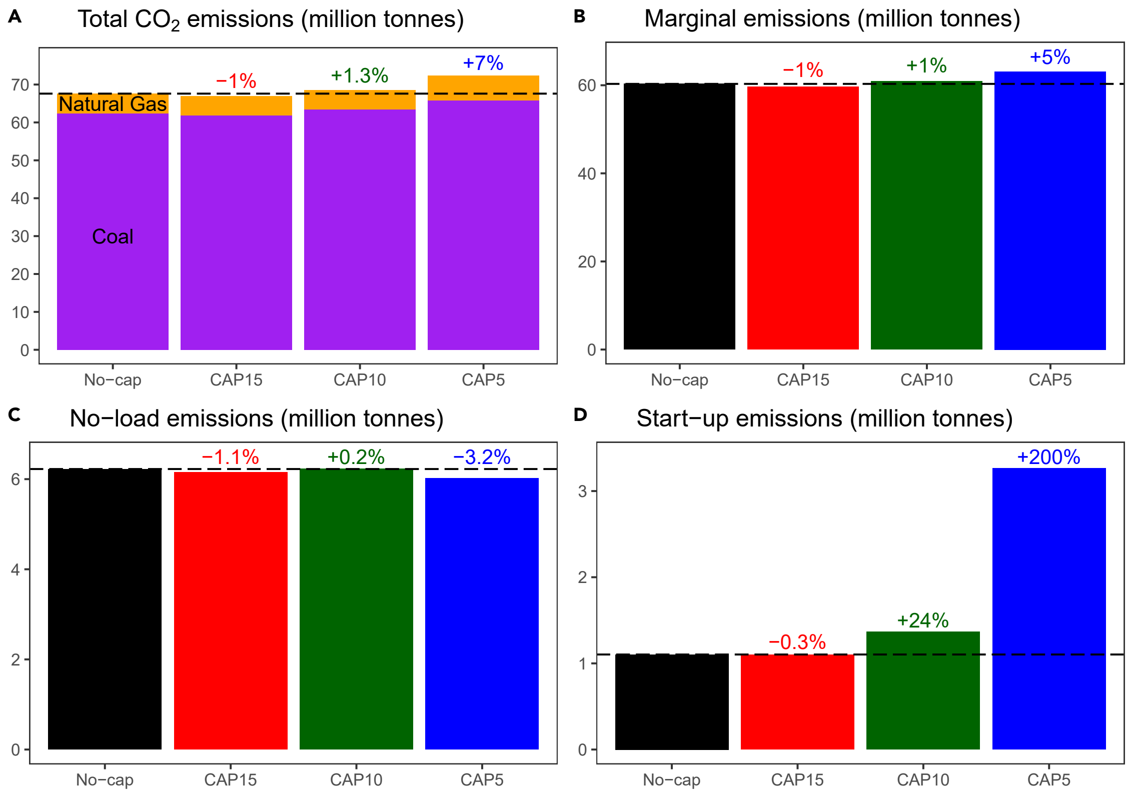

Figure 6. Comparison of CO_2 emissions under different curtailment cap scenarios during 2021–2030 in Qinghai

(A) Total CO_2 emissions.

(B) Marginal CO_2 emissions. (C) No-load CO_2 emissions. (D) Start-up CO_2 emissions.

curtailment caps like China's. In their stringent form, these curtailment cap policies retard the deployment of renewable capacity, reduce the utilization of hydropower resources, and increase the utilization of fossil fuel units. In addition, capping curtailment makes for a more expensive, less reliable power system. Most strikingly, it increases GHG emissions from the power system. These deleterious consequences become significant in a non-linear fashion as the cap policy becomes more stringent. We conclude that capping curtailment is counterproductive to the goals pursued by system operators and policy makers, including the promotion of renewable project development and the reduction of GHG emission from the power system.

All energy policies distort the energy system in one way or another. Curtailment cap policies are likely to convey distorted signals to investors in energy infrastructure at a time when they need to aggressively ramp up renewable project development. By capping curtailment and boosting profits from renewable energy projects, there is a risk of over-investment in renewable energy projects in locations where the grid has limited flexibility to integrate their production. The costs to facilitate this integration would be borne by the system, potentially jeopardizing policy and political support for the net-zero transition. And yet, our results show that stringent curtailment cap policies convey an opposite message to system planners: to meet the curtailment cap, capacity investments in renewables would need to be restricted, whereas investments in flexible but expensive resources would need to increase to ensure that the power system meets its technical constraints. The Qinghai case in this study shows that, were policymakers to insist on capping curtailment at 5% in 2030, system planners would end up under-approving additional renewables capacity by 17% while boosting flexible resource capacity by 43% compared to a no-cap scenario.

Our results also yield insights regarding prudent storage requirements for new resource plans. China's local governments have set various requirements on the storage-renewable ratio of new capacity, with many mandating a ratio of 10% or higher. Our results show that this requirement is appropriate until

2024; however, as VRE penetration grows, the ratio should increase to 20% if no curtailment cap policy is in place, or 30% if curtailment is to be capped at 5%.

As the world transitions to decarbonized energy systems over the coming decades, this work produces a roadmap for prudent and dynamic policymaking and regulation when it comes to the question of renewable electricity curtailment. As policy makers and system planners continue to grapple with the impacts of radically expanding renewables, it would be wise to signal that curtailment strategies must and will change as renewable penetration grows. Our results articulate to these two communities the benefits of relaxing curtailment caps to achieve other policy objectives like increasing renewables development, rendering power supply affordable, minimizing GHG emissions, and ensuring system reliability. They also serve as a warning to renewable energy investors that they should not anticipate maximal electricity integration but should foresee a decline in capacity factor as the penetration of renewables grows.

Limitations of the study

This article focused on the unintended effects of curtailment cap policies on power system decarbonization. It stops short of investigating the impacts of various sources of flexibility on the integration of renewables in different power grids. Flexibility options will only be deployed in accordance with existing policies, as published by local authorities and utilities. In this model, we incorporate those elements of flexibility for which there is evidence in Qinghai (Figure 7). In the longer term, policies encouraging storage deployment,[28] demand side response, enlarged balancing areas,[23] and interconnected and robust regional power grids might be promulgated and end up being essential measures to enhance the integration of renewable generation. These measures would mitigate the unintended consequences of the curtailment cap policy. This article does not analyze the potential interaction effects between flexibility and curtailment cap policies. Future work will explore precisely how flexibility might work together with the curtailment cap policy to help renewable integration as we transition to a deeply decarbonized world. Future work could also include a sensitivity analysis with other power grids that have lower renewable resources to expand the applicability of the conclusion.

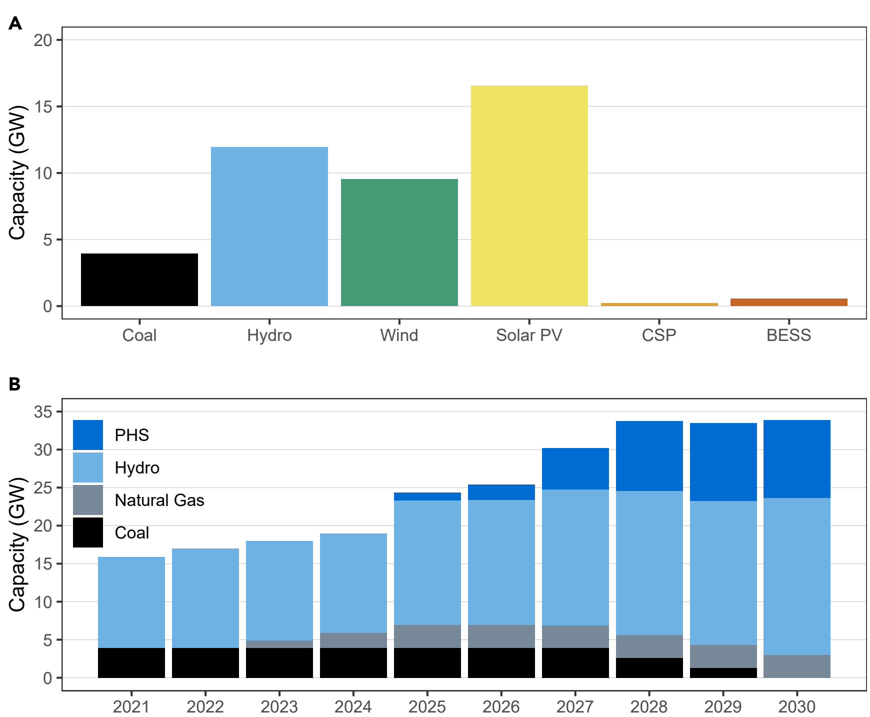

Figure 7. Capacity of electric power generation in Qinghai

(A) Installed capacity of all power resources in 2021.

(B) Capacity expansion planning of coal, natural gas, hydro power, and PHS during 2021–2030.

STAR★METHODS

Detailed methods are provided in the online version of this paper and include the following:

- KEY RESOURCES TABLE
- RESOURCE AVAILABILITY
  - Lead contact
  - Materials availability
  - Data and code availability
- METHOD DETAILS
  - Main equations
  - Capacity expansion planning model
  - Constraints
  - Unit commitment and economic dispatch model

SUPPLEMENTAL INFORMATION

Supplemental information can be found online at https://doi.org/10.1016/j.isci.2023.106967.

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AUTHOR CONTRIBUTIONS

M.L. designed the study. M.L. and Z.L. collected and processed the data. M.L. developed the model and conducted the simulations. Y.D., M.L., A.A., and R.S. wrote the article and drew the figures. All authors discussed the results and commented on the manuscript.

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		
Electricity demand and supply facilities of power system	Various, see Section S1 of the supplemental information (SI) for details	
Parameters of electric power system	Various, see Section S2 of the supplemental information for details	
Solar and wind resource	Li et al. (2022)[54]	https://doi.org/10.1016/j.apenergy.2021.117996
Software and algorithms		
Main equations and model description	Method details	
IBM CPLEX	IBM Software	https://www.ibm.com/products/ilog-cplex-optimization-studio/cplex-optimizer

RESOURCE AVAILABILITY

Lead contact

Further information and requests for resources and reagents should be directed to and will be fulfilled by the lead contact, Mingquan Li (mingquanli@buaa.edu.cn).

Materials availability

This study did not generate new unique reagents.

Data and code availability

Data have been included in the supplemental information along with the paper. Accession numbers are listed in the key resources table.

All original code is available in this paper's supplemental information.

Any additional information required to reanalyze the data reported in this paper is available from the lead contact upon request.

METHOD DETAILS

We optimize and simulate capacity expansion planning and power system operations in the Chinese province of Qinghai from 2021 to 2030. We focus on Qinghai for several reasons: first, it is the only province in China that has achieved 100% all-renewable energy consumption for several consecutive days (more than 7 days during the summer of 2017, a season when the hydropower resource is especially rich). Second, it has the highest proportion of VRE among Chinese provinces.[55] Third, it is rich in both wind and solar resources,[54] and has aggressive VRE development goals,[55] making it an ideal test case for Chinese aspirations to fulfill a 100% renewable energy future.[56]

This research takes 2021 as the base year and optimizes capacity expansion and power system operations in Qinghai until 2030. Capacity expansions of wind, solar PV, concentrating solar power (CSP), and BESS are considered. In this paper, intermittent VRE resources refer to wind and solar PV, and emerging flexible resources refer to BESS and CSP. Changes in the capacities of coal, natural gas, non-pumped hydropower and PHS during the period 2021–2030 are taken from the Qinghai government's planning documents. These show that all coal units will be mothballed by 2030, with most additional demand satisfied by new renewable energy capacity. In addition, capacities of natural gas, hydro power and PHS will gradually increase. Figure 7A shows the installed capacity of all energy resources in 2021: solar PV and hydro have the largest installed capacities, while fossil fuel capacity accounts for less than 10% of the system. Figure 7B shows the government's plans for the evolution of coal, natural gas, hydropower and PHS capacity. Section S1 of the SI contains more details regarding the power system in Qinghai.

We employ a modeling framework that combines capacity expansion planning and economic dispatch. The model minimizes the total power supply system costs while satisfying all economic, technical, operational, and regulatory constraints of power system operations at a high temporal resolution. The modeling framework involves two consecutive steps. First, we run the capacity expansion planning (CEP) model, which reflects system operations in typical days. The results of this model ensure that we can satisfy real-time power system operations while reducing model size. Second, with capacity expansion decisions as given inputs, we run a unit commitment and economic dispatch (UC-ED) model. This model optimizes power system dispatch in each of the 8,760 h of the year, generating more accurate power system operations results than the first model.

The CEP model minimizes the total capital investment and operational costs of the power supply system subject to economic, technical, operational, and regulatory constraints over the entire time period under investigation. The model aims to find the optimal decisions for capacity and timing of investments in various power generation and energy storage technologies. To reduce model size, we use one typical workday and weekend day of a month to represent the whole month. Thus, there are 576 time intervals in a modeled year (24 h per day and 24 typical days per year). In order to eliminate the asymmetry between annualized capital investment costs and operational costs due to the selection of typical days, we multiple operational costs by 8760/576 to obtain annual total operational costs. The constraints of the CEP model include.

- Power supply (minus any over-generation) must equal power demand (minus any under-generation) at each time period. The power demand is equal to the local demand plus exports minus imports. Hourly demand, exports, and imports of electricity, as per Qinghai's future transmission expansion plans, can be found in Section S1.4 of the supplemental information.
- Reserves should be equal or exceed reserve requirements (minus any shortage in reserve).
- Technical constraints of electric generating units, such as minimum/maximum power generation, maximum ramp up/down rates, maximum startup/shutdown ramp rates, minimum up/down hours. Since China's current policy encourages the phasing out of fossil generators rather than investing in flexibility retrofits, no future improvements in thermal unit flexibility are considered.
- Electric power generation from VRE that cannot be integrated into the power system is curtailed.
- Operational constraints of CSP, such as hourly solar energy from a solar field, minimum/maximum energy level, maximum charge/discharge capability, round-trip efficiency and storage decay losses of thermal energy storage, and minimum/maximum power generation of power block.
- Operational constraints of PHS and BESS, such as minimum/maximum energy level, maximum charge/discharge power capability, and round-trip efficiency.

The UC-ED yields the optimal hourly dispatch of existing and new installed energy infrastructure, with capacity expansions prescribed by the CEP model. Mathematically, this model looks similar to the CEP model, with the following key differences. First, they have different time horizons. The CEP model optimizes power system operations in typical days across the whole research period, while the UC-ED model optimizes power system operations for each of the 8760 h in a year and iterates until the last year is completed. Second, they have different decision variables and objective functions. In the CEP model, capacity expansions are decision variables, but in the DA-UC model they are given inputs; as a result, the objective function of the DA-UC model only includes the operational cost of the power supply system and takes the capital investment cost as given. The results from the DA-UC model can be used to analyze the future energy mix, power system reliability, and CO_2 emissions from the power system operation. Three metrics are used to measure the reliability of the power system: over generation, under generation, and unmet reserve. All three metrics incur a system reliability penalty specified in Section S2.3 of the supplemental information.

We solve this large-scale, mixed-integer linear programming (MILP) model using the IBM CPLEX optimization engine on a server with a 32-thread processor with 3.5 GHz and 512 GB of RAM.

Main equations

Here we summarize the parameters and decision variables of the CEP and UC-ED model.

CellPress
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Subscripts	Description	Set	Range
u	Index describing a specific electric generating unit (EGU)	ψ^U	1 to N_U
y	Index describing a specific year	ψ^Y	1 to N_Y
t	Index describing a specific time interval	ψ^T	1 to N_T
m	Index describing a specific month	ψ^M	1 to N_M
Superscripts	**Description**	**Set**	**Range**
EGU	Refers to parameters/variables for EGU (including coal, natural gas, and hydro)		
VRE	Refers to parameters/variables for VRE (including wind and solar PV)		
$Wind$	Refers to parameters/variables for wind		
$Solar$	Refers to parameters/variables for solar PV		
CSP	Refers to parameters/variables for CSP		
ESS	Refers to parameters/variables for ESS (including PHS and BESS)		
PHS	Refers to parameters/variables for PHS		
$BESS$	Refers to parameters/variables for BESS		
$Penalty$	Refers to parameters/variables for system-wide (over/under generation, reserve shortage) penalty		
Cost function	**Description**	**Unit**	**Range**
$TC(\cdot)$	Function of total costs of electric power supply system	RMB	
$TC^{EGUVar}(\cdot)$	Function of total variable electricity generation costs of EGUs	RMB	
$TC^{EGURes}(\cdot)$	Function of total costs for providing reserves of EGUs	RMB	
$TC^{EGUStart}(\cdot)$	Function of total costs for units' start-ups of EGUs	RMB	
$TC^{EGUNL}(\cdot)$	Function of total no-load costs for committed EGUs	RMB	
$TC^{VREInvest}(\cdot)$	Function of total capital investment costs of new VRE	RMB	
$TC^{VREFixOM}(\cdot)$	Function of total fixed O&M costs of new VRE	RMB	
$TC^{VREVar}(\cdot)$	Function of total operational costs of VRE	RMB	
$TC^{CSPInvest}(\cdot)$	Function of total capital investment costs of new CSP	RMB	
$TC^{CSPFixOM}(\cdot)$	Function of total fixed O&M costs of new CSP	RMB	
$TC^{CSPVar}(\cdot)$	Function of total operational costs of CSP	RMB	
$TC^{BESSInvest}(\cdot)$	Function of total capital investment costs of new BESS	RMB	
$TC^{BESSFixOM}(\cdot)$	Function of total fixed O&M costs of new BESS	RMB	
$TC^{ESSVar}(\cdot)$	Function of total operational costs of ESS	RMB	
$TC^{Penalty}(\cdot)$	Function of total penalty for over and under generation and reserve shortage	RMB	
Parameter	**Description**	**Unit**	**Range**
$MC^{EGU}_{m,u}$	Per MWh power generation variable costs of unit u in month m	RMB/MWh	
$RC^{EGU}_{m,u}$	Cost for providing per MWh reserve of unit u in month m	RMB/MWh	
SUC^{EGU}_{u}	Per time start-up cost of unit u	RMB/MW/time	
NLC^{EGU}_{u}	Per MW no-load cost when unit u is committed	RMB/MW	
$Capacity^{EGU}_{y,u}$	Installed capacity of unit u in year y	MW	
Max^{EGU}_{u}	Maximum hourly power generation of unit u	% of capacity	
$Hydro^{EGU}_{m,u}$	Hydro energy resources of hydro unit u in month m	% of capacity	
Min^{EGU}_{u}	Minimum hourly power generation of unit u	% of capacity	
$RRUp^{EGU}_{u}$	Ramp up capability of unit u	% of capacity	
$RRDn^{EGU}_{u}$	Ramp down capability of unit u	% of capacity	
$RRSU^{EGU}_{u}$	Startup ramping capability of unit u	% of capacity	
$RRSD^{EGU}_{u}$	Shutdown ramping capability of unit u	% of capacity	
$MinUT^{EGU}_{u}$	Minimum up time of unit u	Hours	
$MinDT^{EGU}_{u}$	Minimum down time of unit u	Hours	

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Parameter	Description	Unit	Range
$InvestC_y^{Wind}$	Capital investment costs per MW installed capacity of new wind in year y	RMB/MW	
$InvestC_y^{Solar}$	Capital investment costs per MW installed capacity of new solar PV in year y	RMB/MW	
$FixOMC_y^{Wind}$	Annual fixed O&M costs per MW installed capacity of new wind in year y	RMB/MW/Year	
$FixOMC_y^{Solar}$	Annual fixed O&M costs per MW installed capacity of new solar PV in year y	RMB/MW/Year	
$Capacity_y^{VRE}$	Installed capacity of exist wind/solar in year y	MW	
$Resource_t^{VRE}$	Hourly capacity factor of wind/solar energy resources at time interval t	% of capacity	
MC^{Wind}	Marginal cost of wind generation	RMB/MWh	
MC^{Solar}	Marginal cost of solar PV generation	RMB/MWh	
PR_y^{CSP}	Installed power capacity of exist CSP in year y	MW	
ER_y^{CSP}	Installed energy capacity of exist CSP thermal energy storage in year y	MWh	
$MinGen^{CSP}$	Minimum hourly power generation of CSP power block	% of capacity	
SM^{CSP}	Solar multiple of CSP	–	
$Resource_t^{CSP}$	Hourly capacity factor of solar field at time interval t	% of capacity	
$EFCh^{CSP}$	Efficiency of charging energy to CSP thermal energy storage system	%	
$EFDisch^{CSP}$	Efficiency of discharging energy from CSP thermal energy storage system	%	
$LossRate^{CSP}$	Hourly energy loss rate of CSP thermal energy storage system	%	
MC^{CSP}	Marginal cost of CSP power generation	RMB/MWh	
$InvestC_y^{BESS}$	Capital investment costs per MW power rating of new BESS in year y	RMB/MW	
$FixOMC_y^{BESS}$	Annual fixed O&M costs per MW power rating of new BESS in year y	RMB/MW/Year	
MC^{ESS}	Per MWh of charging/discharging energy cost for ESS	RMB/MWh	
PR_y^{ESS}	Installed power rating of exist ESS at year y	MW	
ER_y^{ESS}	Installed energy capacity of exist ESS at year y	MWh	
$EFCh^{ESS}$	Efficiency of charging ESS	%	
$EFDisch^{ESS}$	Efficiency of discharging ESS	%	
$LossRate^{ESS}$	Hourly energy loss rate of ESS	%	
Max^{ESS}	Maximum energy level of ESS	%	
Min^{ESS}	Minimum energy level of ESS	%	
$OverGen^{Penalty}$	Per MWh over generation penalty	RMB/MWh	
$UnderGen^{Penalty}$	Per MWh under generation penalty	RMB/MWh	
$ShortRes^{Penalty}$	Per MWh reserve scarcity penalty	RMB/MWh	
D_t	Power demand at time interval t	MWh	
δ	Annual discount rate	%	
φ	The coefficient to scale up the operational costs from typical hours (576) to the annual level (8760), $\varphi = \frac{8760}{576}$	–	
CAP^{VRE}	Policy mandates of curtailment cap ratio	%	
Decision variable	**Description**	**Unit**	**Range**
$E_{t,u}^{EGU}$	Power generation of unit u at time interval t	MWh/h	≥ 0
$Res_{t,u}^{EGU}$	Amount of reserves provided by unit u at time interval t	MWh/h	≥ 0
$Commit_{t,u}^{EGU}$	Commitment status of unit u at time interval t	–	0, 1
$v_{t,u}^{EGU}$	Startup action of unit u at time interval t	–	0, 1
$w_{t,u}^{EGU}$	Shutdown action of unit u at time interval t	–	0, 1
$NewCap_y^{Wind}$	Capacity of newly built wind farms in year y	MW	≥ 0
$NewCap_y^{Solar}$	Capacity of newly built solar farms in year y	MW	≥ 0
EIn_t^{VRE}	Amount of integrated VRE electricity (wind/solar) at time interval t	MWh/h	≥ 0
ECu_t^{VRE}	Amount of curtailed VRE electricity (wind/solar) at time interval t	MWh/h	≥ 0

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Decision variable	Description	Unit	Range
$NewCap_y^{CSP}$	Capacity of newly built CSP in year y	MW	≥ 0
EIn_t^{CSP}	Direct solar energy integration (with CSP system energy losses considered) at time interval t	MWh/h	≥ 0
ECh_t^{CSP}	Solar power being charged in CSP thermal energy storage system at time interval t	MWh/h	≥ 0
$EDisch_t^{CSP}$	Heat being discharged from CSP thermal energy storage system at time interval t	MWh/h	≥ 0
Res_t^{CSP}	Reserves provided by CSP thermal energy storage system at time interval t	MWh/h	≥ 0
TE_t^{CSP}	Current energy level of CSP thermal energy storage system at time interval t	MWh	≥ 0
$Commit_t^{CSP}$	Commitment status of CSP power block at time interval t	–	0, 1
$NewCap_y^{BESS}$	Capacity of newly built BESS in year y	MW	≥ 0
x_t^{ESS}	Charging status of ESS at time interval t	–	0, 1
y_t^{ESS}	Discharging status of ESS at time interval t	–	0, 1
ECh_t^{ESS}	Power being charged in ESS at time interval t	MWh/h	≥ 0
$EDisch_t^{ESS}$	Power being discharged from ESS at time interval t	MWh/h	≥ 0
Res_t^{ESS}	Reserves provided by ESS at time interval t	MWh/h	≥ 0
TE_t^{ESS}	Current energy level of ESS at time interval t	MWh	≥ 0
$OverGen_t$	Amount of system wide over generation at time interval t	MWh	≥ 0
$UnderGen_t$	Amount of system wide under generation at time interval t	MWh	≥ 0
$ShortRes_t$	Amount of system wide reserve scarcity at time interval t	MWh	≥ 0

Capacity expansion planning model

The CEP model minimizes total costs (Equation 1) subject to constraints (Equations 2–33). All parameters and decision variables are as defined above.

Objective function

The objective of the CEP model is to minimize total discounted electricity supply system costs (include capacity expansion costs and system operational costs) during the research period. These costs consist of.

- Discounted total variable power generation costs of EGUs
- Discounted total reserve costs of EGUs
- Discounted total start-up costs of EGUs
- Discounted total no-load costs of EGUs
- Discounted total capital investment costs of new VRE infrastructure
- Discounted total fixed O&M costs of new VRE infrastructure
- Discounted total operational costs of VRE electricity generation
- Discounted total capital investment costs of new CSP infrastructure
- Discounted total fixed O&M costs of new CSP infrastructure
- Discounted total operational costs of CSP infrastructure
- Discounted total capital investment costs of new BESS infrastructure
- Discounted total fixed O&M costs of new BESS infrastructure
- Discounted total operational cost of both existing and new ESS
- Discounted total system-wide penalty

It must be noted that coal, natural gas, non-pumped hydro power, and PHS during the period 2021–2030 are given as per government plans. Their capital investment and annual fixed O&M costs are treated as fixed and hence are not included in this analysis.

min

$$TC\begin{pmatrix} E^{EGU}_{t,u}, Res^{EGU}_{t,u}, v^{EGU}_{t,u}, Commit^{EGU}_{t,u}, \\ NewCap^{Wind}_{y}, NewCap^{Solar}_{y}, EIn^{VRE}_{t}, ECu^{VRE}_{t}, \\ NewCap^{CSP}_{y}, EIn^{CSP}_{t}, EDisch^{CSP}_{t}, \\ NewCap^{BESS}_{y}, ECh^{ESS}_{t}, EDisch^{ESS}_{t}, \\ OverGen_t, UnderGen_t, ShortRes_t \end{pmatrix}$$

$$= \left[TC^{EGUVar}\left(E^{EGU}_{t,u}\right) + TC^{EGURes}\left(Res^{EGU}_{t,u}\right) + TC^{EGUStart}\left(v^{EGU}_{t,u}\right) + TC^{EGUNL}\left(Commit^{EGU}_{t,u}\right)\right] + \left[TC^{VREInvest}\left(NewCap^{Wind}_{y}, NewCap^{Solar}_{y}\right)\right.$$
$$\left. + TC^{VREFixOM}\left(NewCap^{Wind}_{y}, NewCap^{Solar}_{y}\right) + TC^{VREVar}\left(EIn^{VRE}_{t}, ECu^{VRE}_{t}\right)\right] + \left[TC^{CSPInvest}\left(NewCap^{CSP}_{y}\right) + TC^{CSPFixOM}\left(NewCap^{CSP}_{y}\right)\right.$$
$$\left. + TC^{CSPVar}\left(EIn^{CSP}_{t}, EDisch^{CSP}_{t}\right)\right] + \left[TC^{BESSInvest}\left(NewCap^{BESS}_{y}\right) + TC^{BESSFixOM}\left(NewCap^{BESS}_{y}\right) + TC^{ESVar}\left(ECh^{ESS}_{t}, EDisch^{ESS}_{t}\right)\right]$$
$$+ \left[TC^{Penalty}\left(OverGen_t, UnderGen_t, ShortRes_t\right)\right] \quad \text{(Equation 1)}$$

It is explained as below.

1. Costs of EGUs	
1.1 Total operational costs of EGUs during the research period	
(1) Variable production cost	$TC^{EGUVar}(E^{EGU}_{t,u}) = \sum_y \sum_{m\in y} \sum_{t\in y,m} \sum_u \left[E^{EGU}_{t,u} \times MC^{EGU}_{m,u} \times \frac{1}{(1+\delta)^y}\right] \times \varphi$ For a coal or natural gas EGU, its per MWh variable generation cost ($MC^{Gen}_{m,u}$) is the result of (1) fuel price in month *m* and (2) marginal fuel consumption per MWh electricity generation.
(2) Reserves cost	$TC^{EGURes}(Res^{EGU}_{t,u}) = \sum_y \sum_{m\in y} \sum_{t\in y,m} \sum_u \left[Res^{EGU}_{t,u} \times RC^{EGU}_{m,u} \times \frac{1}{(1+\delta)^y}\right] \times \varphi$
(3) Start-up cost	$TC^{EGUStart}(v^{EGU}_{t,u}) = \sum_y \sum_{t\in y} \sum_u \left[v^{EGU}_{t,u} \times SUC^{EGU}_{u} \times Capacity^{EGU}_{y,u} \times \frac{1}{(1+\delta)^y}\right] \times \varphi$
(4) No load cost	$TC^{EGUNL}(Commit^{EGU}_{t,u}) = \sum_y \sum_{t\in y} \sum_u \left[Commit^{EGU}_{t,u} \times NLC^{EGU}_{u} \times Capacity^{EGU}_{y,u} \times \frac{1}{(1+\delta)^y}\right] \times \varphi$
2. Costs of intermittent VRE	
2.1 Total capital investment and annual fixed O&M costs of new VRE during the research period	
(1) Capital investment cost	$TC^{VREInvest}(NewCap^{Wind}_y, NewCap^{Solar}_y) = \sum_y \left[TC^{WindInvest}_y(NewCap^{Wind}_y) \times \frac{1}{(1+\delta)^y} + TC^{SolarInvest}_y(NewCap^{Solar}_y) \times \frac{1}{(1+\delta)^y}\right]$ Capital cost of new wind ($TC^{WindInvest}_y(NewCap^{Wind}_y)$) is the result of (1) new capacity ($NewCap^{Wind}_y$), (2) per MW capital costs ($InvestC^{Wind}_y$), (3) construction time (year), and (4) technical life time (year); it is similar for the capital costs of other new energy infrastructure.
(2) Fixed O&M cost	$TC^{VREFixOM}(NewCap^{Wind}_y, NewCap^{Solar}_y) = \sum_y \left[TC^{WindFixOM}_y(NewCap^{Wind}_y) \times \frac{1}{(1+\delta)^y} + TC^{SolarFixOM}_y(NewCap^{Solar}_y) \times \frac{1}{(1+\delta)^y}\right]$
2.2 Total operational costs of both existing and new VRE infrastructure during the research period	

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Continued

1. Costs of EGUs	
1.1 Total operational costs of EGUs during the research period	
Operational cost	$TC^{VREVar}\left(EIn_t^{VRE}, ECu_t^{VRE}\right) = \sum_y \sum_{t\in y}\left[MC^{VRE} \times \left(EIn_t^{VRE} + ECu_t^{VRE}\right) \times \frac{1}{(1+\delta)^y}\right] \times \varphi$
3. Costs of CSP	
3.1 Total capital investment and annual fixed O& M costs of additional CSP during the research period	
(1) Capital investment cost	$TC^{CSPInvest}\left(NewCap_y^{CSP}\right) = \sum_y \left[TC_y^{CSPInvest}\left(NewCap_y^{CSP}\right) \times \frac{1}{(1+\delta)^y}\right]$
(2) Fixed O&M cost	$TC^{CSPFixOM}\left(NewCap_y^{CSP}\right) = \sum_y \left[TC_y^{CSPFixOM}\left(NewCap_y^{CSP}\right) \times \frac{1}{(1+\delta)^y}\right]$
3.2 Total operational costs of existing and new CSP during the research period	
Operational cost	$TC^{CSPVar}\left(EIn_t^{CSP}, EDisch_t^{CSP}\right) = \sum_y \sum_{t\in y}\left[MC^{CSP} \times \left(EIn_t^{CSP} + EDisch_t^{CSP} \times EFDisch^{CSP}\right) \times \frac{1}{(1+\delta)^y}\right] \times \varphi$
4. Costs of ESS	
4.1 Total capital investment and annual fixed O& M costs of additional BESS during the research period	
(1) Capital investment cost	$TC^{BESSInvest}\left(NewCap_y^{BESS}\right) = \sum_y \left[TC_y^{BESSInvest}\left(NewCap_y^{BESS}\right) \times \frac{1}{(1+\delta)^y}\right]$
(2) Fixed O&M cost	$TC^{BESSFixOM}\left(NewCap_y^{BESS}\right) = \sum_y \left[TC_y^{BESSFixOM}\left(NewCap_y^{BESS}\right) \times \frac{1}{(1+\delta)^y}\right]$
4.2 Total operational costs of existing and new ESS during the research period	
Operational costs	$TC^{ESSVar}\left(ECh_t^{ESS}, EDisch_t^{ESS}\right) = \sum_y \sum_{t\in y}\left[MC^{ESS} \times \left(ECh_t^{ESS} + EDisch_t^{ESS}\right) \times \frac{1}{(1+\delta)^y}\right] \times \varphi$
5. System-wide penalty	

$$TC^{Penalty}\left(OverGen_t, UnderGen_t, ShortRes_t\right) = \sum_y \sum_{t\in y}\left[\left(OverGen_t \times OverGen^{Penalty} + UnderGen_t \times UnderGen^{Penalty} + ShortRes_t \times ShortRes^{Penalty}\right) \times \frac{1}{(1+\delta)^y}\right] \times \varphi$$

Constraints

Power balance equation

For each time interval, power supply (minus any over-generation) must equal power demand (minus any under-generation). The power demand is equal to the local demand plus exports minus imports.

$\sum_u E_{t,u}^{EGU}$	Power generation from exist and new coal, natural gas, and hydro EGUs
$+ EIn_t^{VRE}$	Integrated energy from exist and new wind and solar farms
$+ EIn_t^{CSP} + EDisch_t^{CSP} \times EFDisch^{CSP}$	Energy being discharged from existing and new PHS and BESS facilities
$-\ ECh_t^{ESS}$	Energy being charged into existing and new PHS and BESS facilities
$-\ OverGen_t + UnderGen_t$	Any over generation or under generation of power system
$=$	
D_t	Power demand at time step t

$$\forall t \qquad \text{(Equation 2)}$$

Reserve constraints

We assume that EGUs (coal, natural gas, and hydro), CSP energy storage, PHS and BESS provide reserve resources for electric power system.

$\sum_{u} Res_{t,u}^{EGU}$	Reserve provided by existing and new coal, natural gas, and hydro EGUs
$+ Res_{t}^{CSP} \times EFDisch^{CSP}$	Reserve provided by exist and new CSP facilities
$+ Res_{t}^{ESS} \times EFDisch^{ESS}$	Reserve provided by exist and new PHS and BESS facilities
$+ ShortRes_{t}$	Any reserve shortage of power system
$\geq$	
$ResReq_{t}$	Reserve requirements for time step t

$$\forall t \quad \text{(Equation 3)}$$

Operations constraints of each EGU

Generating units have technical flexibility constraints, such as range of generation, maximum ramping up/down capability, minimum up/down time. This research includes these technical constraints of generating units.

(1) Maximum hourly generation constraint for fossil fuel EGUs

$$E_{t,u}^{EGU} + Res_{t,u}^{EGU} \leq Capacity_{y,u}^{EGU} \times Max_{u}^{EGU} \times Commit_{t,u}^{EGU} \forall y, t \in y, u \in Coal\ or\ Natural\ gas \quad \text{(Equation 4)}$$

(2) Maximum hourly generation constraint for hydro EGUs

$$E_{t,u}^{EGU} + Res_{t,u}^{EGU} \leq Capacity_{y,u}^{EGU} \times Max_{u}^{EGU} \forall y, t \in y, u \in Hydro \quad \text{(Equation 5)}$$

$$\sum_{t \in m} \left(E_{t,u}^{EGU} + Res_{t,u}^{EGU} \right) \leq \sum_{t \in m} \left(Capacity_{y,u}^{EGU} \times Hydro_{m,u}^{EGU} \right) \forall y, m \in y, t \in m, u \in Hydro \quad \text{(Equation 6)}$$

(3) Minimum hourly generation constraint

$$E_{t,u}^{EGU} \geq Capacity_{y,u}^{EGU} \times Min_{u}^{EGU} \times Commit_{t,u}^{EGU} \forall y, t \in y, u \quad \text{(Equation 7)}$$

(4) Ramp up capability constraint

$$E_{t,u}^{EGU} - E_{t-1,u}^{EGU} \leq Capacity_{y,u}^{EGU} \times RRUp_{u}^{EGU} \times Commit_{t-1,u}^{EGU} + Capacity_{y,u}^{EGU}$$
$$\times RRSU_{u}^{EGU} \times v_{t,u}^{EGU} - Capacity_{y,u}^{EGU} \times RRSD_{u}^{EGU} \times w_{t,u}^{EGU} \forall y, t \in y, u \quad \text{(Equation 8)}$$

(5) Ramp down capability constraint

$$E_{t-1,u}^{EGU} - E_{t,u}^{EGU} \leq Capacity_{y,u}^{EGU} \times RRDn_{u}^{EGU} \times Commit_{t,u}^{EGU} + Capacity_{y,u}^{EGU}$$
$$\times RRSD_{u}^{EGU} \times w_{t,u}^{EGU} - Capacity_{y,u}^{EGU} \times RRSU_{u}^{EGU} \times v_{t,u}^{EGU} \forall y, t \in y, u \quad \text{(Equation 9)}$$

(6) Relationship between start-up action, shut-down action and unit commitment status

$$v_{t,u}^{EGU} = \begin{cases} 1, if\ Commit_{t,u}^{EGU} - Commit_{t-1,u}^{EGU} = 1 \\ 0, otherwise \end{cases} \forall t, u \quad \text{(Equation 10)}$$

$$w_{t,u}^{EGU} = \begin{cases} 1, if\ Commit_{t-1,u}^{EGU} - Commit_{t,u}^{EGU} = 1 \\ 0, otherwise \end{cases} \forall t, u \quad \text{(Equation 11)}$$

(7) Initial period minimum up time requirement

$$\sum_{t=1}^{InitMinUp_u} \left(1 - Commit_{t,u}^{EGU}\right) = 0 \forall u \quad \text{(Equation 12)}$$

(8) Transition period minimum up time requirement

$$\sum_{j=t}^{t+MinUT_u-1} \left(Commit_{j,u}^{EGU}\right) \geq MinUT_u^{EGU} \times \left(Commit_{t,u}^{EGU} - Commit_{t-1,u}^{EGU}\right) \forall u, \forall t \in \{InitMinUp_u + 1, T - MinUT_u^{EGU} + 1\} \quad \text{(Equation 13)}$$

(9) Final period minimum up time requirement

$$\sum_{k=t}^{T} \left(Commit_{k,u}^{EGU} - \left(Commit_{t,u}^{EGU} - Commit_{t-1,u}^{EGU}\right)\right) \geq 0 \forall u, \forall t \in \{T - MinUT_u^{EGU} + 2, T\} \quad \text{(Equation 14)}$$

(10) Initial period minimum down time requirement

$$\sum_{t=1}^{InitMinDown_u} Commit_{t,u}^{EGU} = 0 \forall u \quad \text{(Equation 15)}$$

(11) Transition period minimum down time requirement

$$\sum_{j=t}^{t+MinDT_u-1} \left(1 - Commit_{j,u}^{EGU}\right) \geq MinDT_u^{EGU} \times \left(Commit_{t-1,u}^{EGU} - Commit_{t,u}^{EGU}\right) \forall u, \forall t \in \{InitMinDown_u + 1, T - MinDT_u^{EGU} + 1\} \quad \text{(Equation 16)}$$

(12) Final period minimum down time requirement

$$\sum_{j=t}^{T} \left(\left(1 - Commit_{j,u}^{EGU}\right) - \left(Commit_{t-1,u}^{EGU} - Commit_{t,u}^{EGU}\right)\right) \geq 0 \forall u, \forall t \in \{T - MinDT_u^{EGU} + 2, T\} \quad \text{(Equation 17)}$$

Intermittent VRE integration constraints

These constraints define the operation of intermittent VRE technologies. For each of the existing and new wind and solar farms, the sum of integrated and curtailed renewable energy should equal VRE electricity generation. We take the existing VRE facilities as an example and model their operations as follows. New VRE facilities have a similar equation (not shown).

$$EIn_t^{VRE} + ECu_t^{VRE} = Capacity_y^{VRE} \times Resource_t^{VRE} \forall y, t \in y \quad \text{(Equation 18)}$$

Please refer to the SI, S1.3 for more details of methods to calculate hourly capacity factor ($Resource_t^{VRE}$).

We include curtailment cap policy constraints in intermittent VRE operations. For each year, total curtailed VRE electricity cannot exceed the allowed curtailment ratio from policy mandates.

$$\sum_{t\in y} ECu_t^{VRE} \le CAP^{VRE} \times \sum_{t\in y}\left(Capacity_y^{VRE} \times Resource_t^{VRE}\right) \forall y \quad \text{(Equation 19)}$$

CSP operations constraints

All CSPs in Qinghai are equipped with thermal energy storage, and their output variations are significantly eliminated. CSPs have operational constraints, and their operations can be simplified as follows: the heliostat field reflects solar energy to a receiver tower and thus heats a fluid. The energy can be used to heat steam in a heat exchanger. After that, the energy can be directly used by a steam turbine to generate electricity; or can be stored in a thermal energy storage system for later use.

We model the operations for each of the existing and new CSP facilities. We take the existing CSP facilities as an example and model their operations as follows:

$$EIn_t^{CSP} + ECh_t^{CSP} = Gen_t^{CSP} \forall t \quad \text{(Equation 20)}$$

Gen_t^{CSP} is a result of CSP power capacity (PR_y^{CSP}), solar multiple SM^{CSP}, hourly solar energy resources ($Resource_t^{CSP}$), energy losses for the heliostat field and receiver tower, and some other system losses.

$$EIn_t^{CSP} + \left(EDisch_t^{CSP} + Res_t^{CSP}\right) \times EFDisch^{CSP} \le PR_y^{CSP} \times Commit_t^{CSP} \forall y, t\in y \quad \text{(Equation 21)}$$

$$EIn_t^{CSP} + EDisch_t^{CSP} \times EFDisch^{CSP} \ge PR_y^{ES} \times MinGen^{CSP} \times Commit_t^{CSP} \forall y, t\in y \quad \text{(Equation 22)}$$

$$EDisch_t^{CSP} + Res_t^{CSP} - ECh_t^{CSP} \times EFCh^{CSP} \le TE_{t-1}^{CSP} \times \left(1 - LossRate^{CSP}\right) \forall t \quad \text{(Equation 23)}$$

$$TE_t^{CSP} \le ER_y^{CSP} \forall y, t\in y \quad \text{(Equation 24)}$$

$$TE_t^{CSP} = TE_{t-1}^{CSP} \times \left(1 - LossRate^{CSP}\right) - EDisch_t^{CSP} + ECh_t^{CSP} \times EFCh^{CSP} \forall t \quad \text{(Equation 25)}$$

ESS operations constraints

Energy storage systems have operational constraints, such as maximum/minimum energy level of storage system, maximum charging/discharging power, and so on. This research includes these operational constraints. We model the operations for each of the existing and new BESS and PHS facilities. We take the existing BESS facilities as an example and model their operations as follows:

(1) Maximum energy level constraint (energy level in MWh cannot exceed its allowed upper bound):

$$TE_t^{ESS} \le Max^{ESS} \times ER_y^{ESS} \forall y, t\in y \quad \text{(Equation 26)}$$

(2) Minimum energy level constraint (energy level in MWh cannot be lower than its allowed lower bound):

$$TE_t^{ESS} \ge Min^{ESS} \times ER_y^{ESS} \forall y, t\in y \quad \text{(Equation 27)}$$

(3) Power charging limit (charging power in MW cannot exceed its power charging capacity):

$$ECh_t^{ESS} \le PR_y^{ESS} \times x_t^{ESS} \forall y, t\in y \quad \text{(Equation 28)}$$

(4) Power discharging limit (discharging power in MW cannot exceed its power discharging capacity):

$$\left(EDisch_t^{ESS} + Res_t^{ESS}\right) \times EFDisch^{ESS} \le PR_{y,p}^{ESS} \times y_{t,p}^{ESS} \forall y, t\in y \quad \text{(Equation 29)}$$

(5) Maximum discharged power cannot exceed its available energy from energy storage system

$$EDisch_t^{ESS} + Res_t^{ESS} - ECh_t^{ESS} \times EFCh^{ESS} \leq TE_{t-1}^{ESS} \times \left(1 - LossRate^{ESS}\right) - Min^{ESS} \times ER_y^{ESS} \forall y, t \in y \tag{Equation 30}$$

(6) Energy level balance constraints:

$$TE_t^{ESS} = TE_{t-1}^{ESS} \times \left(1 - LossRate^{ESS}\right) - EDisch_t^{ESS} + ECh_t^{ESS} \times EFCh^{ESS} \forall t \tag{Equation 31}$$

(7) Charge and discharge state exclusive:

$$x_t^{ESS} = \begin{cases} 1, & if\ ECh_t^{ESS} > 0 \\ 0, & otherwise \end{cases} \forall t \tag{Equation 32}$$

$$y_t^{ESS} = \begin{cases} 1, & if\ EDisch_t^{ESS} > 0 \\ 0, & otherwise \end{cases} \forall t \tag{Equation 33}$$

Unit commitment and economic dispatch model

All parameters and decision variables in the UC-ED model are also as defined above, with the only difference being that the capacity expansion variables ($NewCap_y^{Wind}$,$NewCap_y^{Solar}$,$NewCap_y^{CSP}$,$NewCap_y^{BESS}$) are not decision variables but instead input parameters set by the results of the CEP model. The UC-ED model minimizes total operational costs with capital and annual fixed O&M costs in Equation 1 as given subject to constraints (Equations 2–33).