Integrating wind into China's coal-heavy electricity system

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Abstract:

Expanding the use of wind energy for electricity generation forms an integral part of China's efforts to address degraded air quality and climate change. We develop an hourly dispatch model to analyze how much wind resource can be accessed given the variable nature of wind and its implications for electricity system operation. We estimate potential grid-integrated economic wind generation in 2030 at 2.6 Petawatt-hours (PWh) per year, 26% of total projected electricity demand, which, while plentiful, is only 10% of total estimated physical potential. Grid integration, in particular the assumed flexibility of thermal generation, accounts for the greatest uncertainty in estimates of exploitable wind resources, with estimates ranging from 2.1 - 3.1 PWh/yr. Increasing the operational flexibility of China's coal fleet would allow wind to deliver nearly three-fourths of China's 2030 20% non-fossil primary energy target, a core element of the country's international climate commitment. Importantly, once integration costs and curtailment are considered, a higher fraction of grid-integrated economic wind would be provided by locations proximate to load centers instead of by distant wind-rich areas via long distance high-voltage transmission.

Significance statement:

China, the world's largest energy consumer and greenhouse gas emitter, has made deploying wind electricity a cornerstone of long-term plans to mitigate climate change, air pollution and other energy-related environmental impacts. Following rapid expansion in recent years, especially in remote, less populous areas, wind has faced significant challenges integrating on the coal-heavy power grid due to its fundamental operational differences compared to conventional energy sources. We present the first assessment of China's wind energy potential and its regional distribution that incorporates an operational model of the grid and undertakes systematic exploration of key uncertainties.

Introduction

China's electricity generation has grown 152% over the last decade, with around three-fourths of this increase met by coal[1]. Looking ahead, expanding wind electricity is a key focus of national policy initiatives to address degraded local air quality and global climate change. By the end of 2015, China's wind installations reached 129 Gigawatts (GW), the world's largest, and wind generation rose to 186 Terawatt-hours (TWh) per year, 3.3% of total generation[2]. By 2020, officials are targeting installed wind capacity of 200 GW and annual wind generation of 390 TWh. Long-term projections for capacity are highly uncertain, ranging from 400-1200 GW in 2030 and 1000-2000 GW in 2050, accounting for as much as 30% of total projected electricity demand[3].

Rapid expansion of wind underpins China's pledge in the 2015 global climate talks in Paris to increase the share of non-fossil sources in national primary energy use to 20% by 2030. Focusing on 2030, we quantify China's grid-connected wind energy potential and its sensitivity to multiple sources of uncertainty. In our base case, we find that wind electricity at or below a marginal cost of 0.6 yuan/kWh (inclusive of system-wide integration costs) could deliver 11.9% of China's projected primary energy demand in 2030, reducing heavily polluting coal-based electricity in China's northern provinces. With increased coal flexibility, we find this share could increase to 14.0%, nearly three-fourths of China's 2030 non-fossil energy target. Moreover, maximizing China's grid-connected wind potential as part of non-fossil energy deployment efforts could enable the country to exceed its 2030 non-fossil energy target by a large margin, with the total non-fossil contribution reaching 28% of total primary energy in 2030.

Leading assessments of China's wind resources differ in their choice of wind datasets, physical constraints, expected tariff levels, and projections of future costs[3–9]. These assessments play a central role in policy and planning decisions, from the selection of appropriate feed-in tariff (FIT) levels to grid and generation expansion plans. However, many assessments to date do not consider the challenge of grid integration: how operational rules of the power system treat wind vis-à-vis existing generation and transmission network constraints. Wind policy and resulting siting decisions that focus on resource quality alone may not be efficient once integration challenges are considered. For example, several of China's nine "10-gigawatt wind power bases," which are sited mostly in remote areas with the best resource quality and far from load centers, have experienced large-scale (40%) forced spillage of wind energy[2], known as curtailment, and most bases will require significant inter-regional transmission.

In this study, we start from an assessment of physical wind resources, and evaluate the effect of additional layers of system complexity on wind electricity potential, using the most recent data, projections, policies and empirically-grounded parameter sensitivities. We report available wind in terms of physical potential (total generation assuming maximum deployment), economic potential (total generation given prevailing electricity tariffs exclusive of integration constraints and costs), and grid-integrated potential (total economic generation inclusive of integration constraints and costs).

Physical wind resource potential represents an upper bound on annual usable wind-generated electricity assuming full deployment. Leading assessments of China's wind resource potential range from 6-25 Petawatt-hours (PWh)/yr (onshore) and 1.4-11 PWh/yr (offshore)[3–9]. These differences are attributable to wind speed data and analysis techniques, wind farm layout assumptions, turbine technologies, and physical constraints on available onshore and offshore sites. Economic wind resource assessments restrict consideration of potential wind sites to those with positive economic returns, and are subject to characteristic uncertainties of the wind power sector, including wind turbine cost reductions and revenue streams that depend on government support (e.g., the FIT). Previous estimates for the economic potential of wind in China are in the range 1.8-7 PWh/yr (onshore) and 0.4-5 PWh/yr (offshore)[3–9].

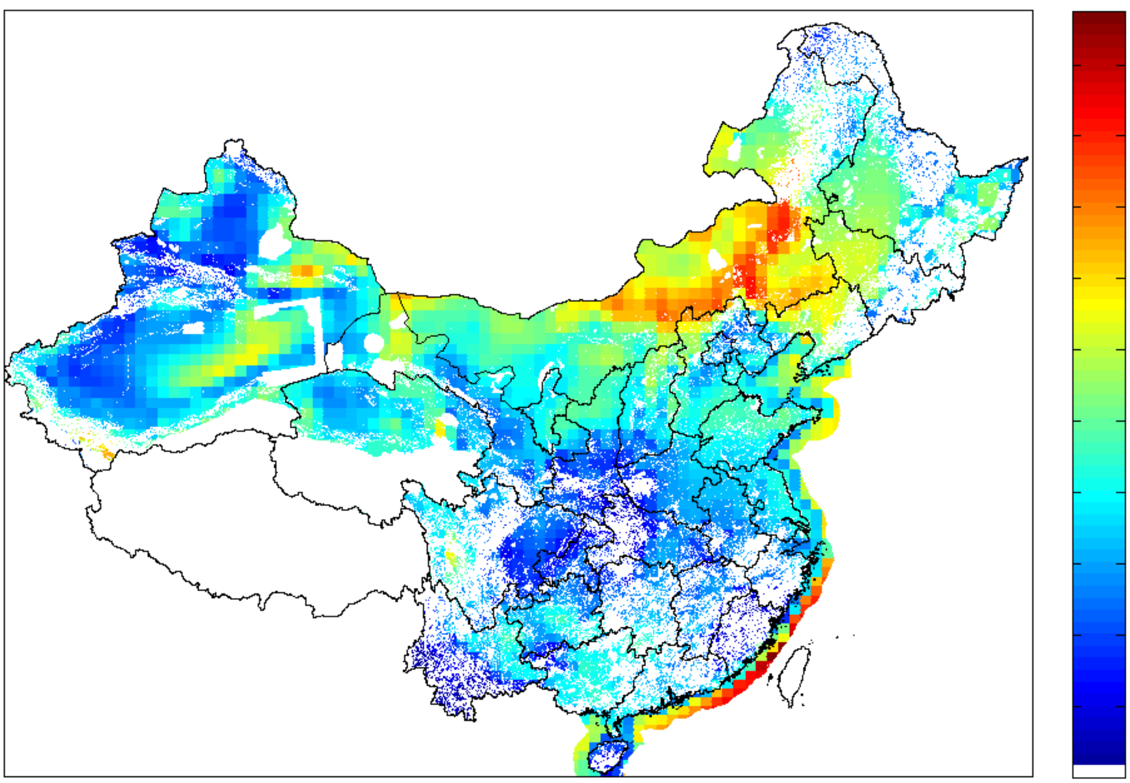

Figure 1. Wind capacity factors (white areas are unsuitable for wind farm construction and excluded from the analysis).

Results

We find significant physical and economic onshore wind potential, in line with or exceeding previous estimates due to turbine technology improvement and cost reductions[3–6]. The spatial distribution of wind capacity factors across China is shown in Figure 1, after excluding areas unsuitable for wind farm construction, as described in the materials and methods. Total physical potential ranges from 13.1-39.5 PWh/yr, which is 1.3-4 times China's total projected electricity demand in 2030 of 9.9 PWh/yr, with the range depending primarily on turbine spacing assumptions. Economic potential under tariffs from 0.5 to 0.7 yuan/kWh and other cost assumptions is plentiful: 12.6-21.6 PWh/yr, which is 1.3-2.2 times China's projected electricity demand in 2030. However, we find significantly lower grid-integrated economic onshore wind potential: 1.9-2.6 PWh/yr, equivalent to 19%-26% of total projected 2030 electricity demand.

Table 1. Main sensitivities of wind potential projected by this study (results are deviations from the base case, holding other variables constant).

Parameter	**Total Potential (PWh)**		
Sensitivity:	**Base**	**Low**	**High**
Physical	26.4		
Onshore: Spacing	22.5	13.1	39.5
Offshore: Spacing	3.9	3.5	4.3
Offshore: Water depth	--	1.5	5.6
Economic	17.8		
Capital cost	--	14.4	21.7
O&M cost	--	15.2	19.9
Grid-integrated	2.59		
Spacing	--	2.51	2.65
Capital cost	--	2.24	2.87
O&M cost	--	2.29	2.82
Reserve/ramping costs	--	2.59	2.61
UHV cost	--	2.51	2.62
Coal flexibility	--	2.07	3.05

Physical offshore potential is estimated at 1.5-5.6 PWh/yr, within the range of previous assessments[8], with the maximum water depth the most influential uncertain parameter. This analysis estimates economic offshore potential at 1.0-2.0 PWh/yr under recent offshore concession prices of 0.60-0.70 yuan/kWh, in line with other economic assessments[7,9]. Despite abundant physical potential, however, significantly higher capital costs relative to onshore installations limit cost-effective expansion. Once the costs of integrating offshore and onshore wind on the grid are considered, this analysis finds very limited economic offshore potential of 0.1-0.5 PWh/yr, even with the favorable properties of anti-correlation and more steady offshore winds[9]. The onshore and offshore wind potential is estimated at 2.1-3.1 PWh, and it suggests that wind generation alone could account for 9.6-14.2% of primary energy, contributing generously to China's 20% non-fossil energy commitment (see Table 1 and Figure 2).

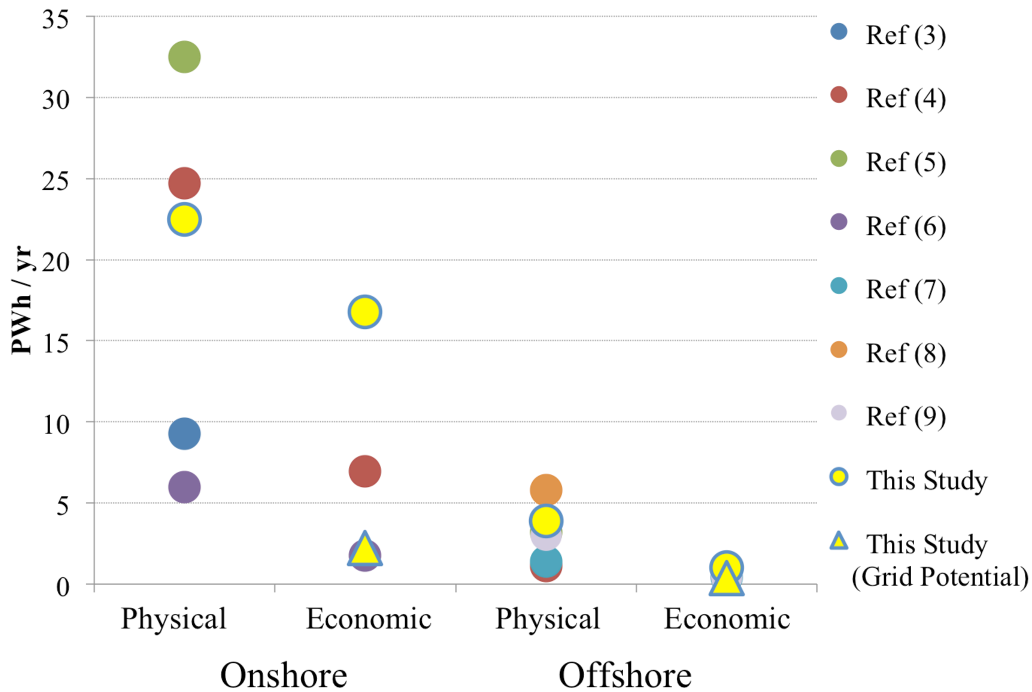

Figure 2. Base case estimates of onshore and offshore wind potential in this study, compared with previous studies.

The influence of parameter sensitivities differs across physical, economic, and grid-integrated potential. The turbine spacing parameter has a far more limited effect on grid-integrated economic potential because there is significant area with comparable wind resources available in each grid region prior to accounting for integration penalties. In effect, the geographic extent of wind farms can be expanded to avoid wake effects before running out of high wind resource areas. Sensitivity to economic assumptions such as capital and operation and maintenance costs is reduced when considering grid integration, though is still more important compared to physical parameters.

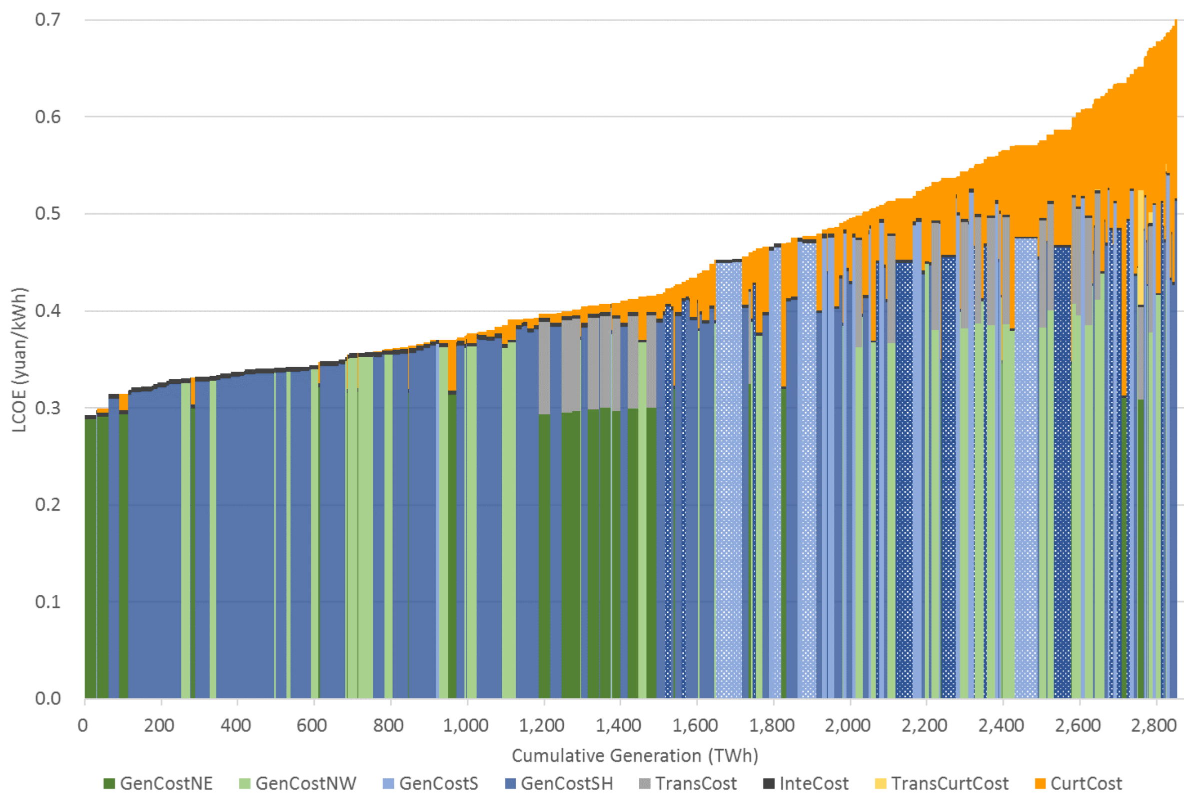

Figure 3. Supply curve of grid-integrated wind in the base case, with generation, integration, transmission and curtailment costs (if applicable). NW – Northwest, NE – Northeast, S – South, SH – *SanHua* (shaded regions are offshore). GenCost – generation cost, TransCost – UHV transmission cost, ReRaCost – reserve and ramping costs, TransCurtCost – curtailment cost due to transmission capacity limit, CurtCost – curtailment cost due to integrated region's generation mix.

The location of the marginal kilowatt-hour of wind supplied will depend on the interaction of generation, transmission, and integration costs. We separately model the cost of deploying wind in four major grid regions in China, the Northwest (NW), Northeast (NE), South (S), and "*Sanhua*" (SH), the last of which aggregates three grid regions located in the populous central part of the country. We further consider two major inter-regional transmission pathways (NW-SH and NE-SH), based on current ultra-high voltage (UHV) transmission projects. When ordered from least to greatest on the basis of total levelized cost per kilowatt-hour, all regions deploy wind, integration costs increase significantly across the system, and long-distance UHV transmission is employed for much of the wind generation in the NW and NE regions (see Figure 3).

The imbalance in electricity consumption between the large demand center SH and wind-rich regions (NW and NE) – where SH represents roughly 5-8 times NW and NE demand in 2030 – requires significant transmission expansion to capture greater quantities of wind (see Figure 4). In the base case, 21% and 14% of total nationwide wind generation comes from the NW and NE regions, respectively, of which 37% and 58% is exported to SH.

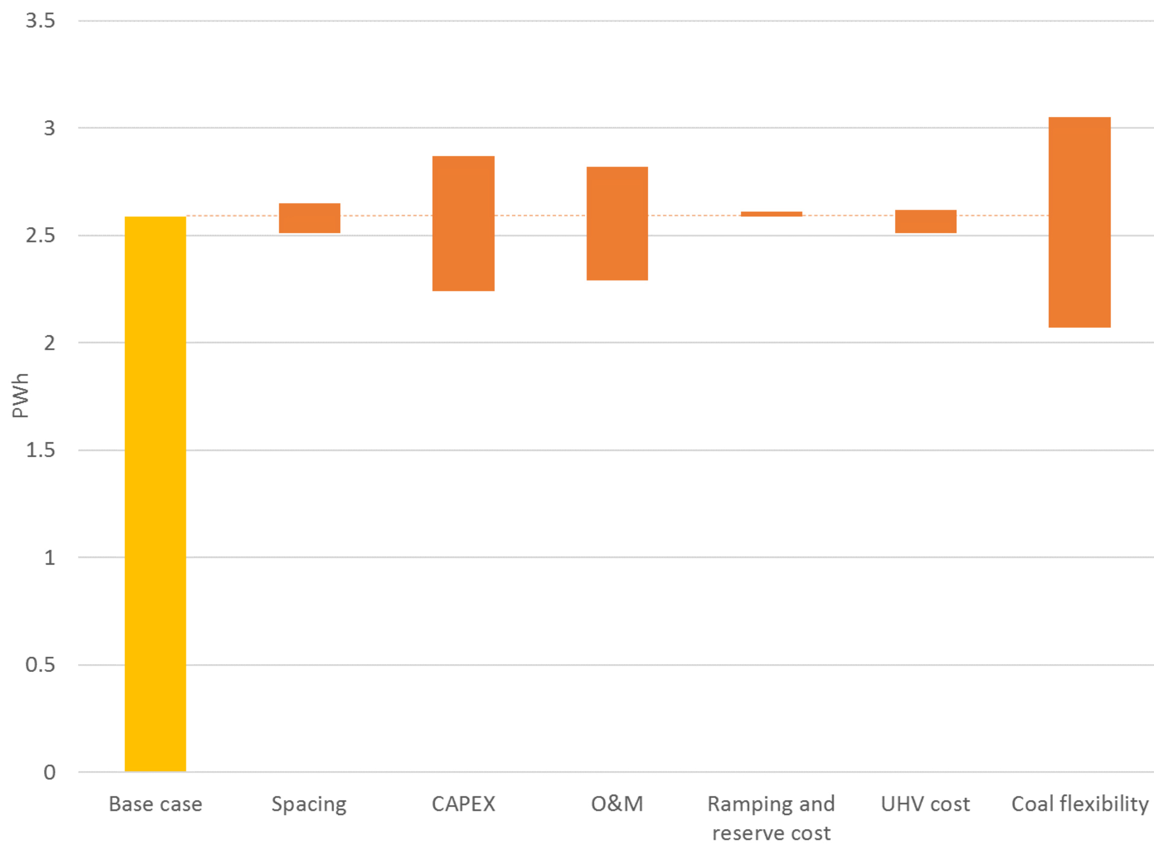

Figure 4. Sensitivities of grid-integrated economic wind potential to assumptions on turbine spacing, capital cost, operating and maintenance (O&M) cost, ramping and reserve cost, ultra-high voltage (UHV) transmission cost, and operational flexibility of coal generation.

We test the sensitivity of our results to several sources of uncertainty that affect grid integration. In many cases, enhancing flexibility such as through simplified energy storage options and demand response can increase total wind potential by up to 8%. The largest uncertainty, relating to generator scheduling practices of the grid company and coal unit flexibility, can yield differences in estimated potential of approximately ±20%.

While the dispatch model used in our analysis is designed to capture core aspects of the electricity system that affect integration, estimates could be further refined by incorporating additional sources of spatial and temporal detail into the model. These sources of detail include increasing the temporal resolution of the model to capture intra-hourly dynamics, simulating the impact of *ad hoc* administrative constraints on dispatch, capturing inter-provincial transmission bottlenecks within regions and expected changes in capacity, modeling explicitly how multiple forms of intermittent renewable energy interact under a wide range of assumptions about their prioritization relative to other generation types, and explicitly resolving CO_2 penalties associated with increased coal ramping to refine estimates of the CO_2 impacts. A thorough representation of many of these factors would require extensive hand collection of data from national and local sources, many of which are considered confidential. Moreover, while additional detail would adjust the ranges of grid-integrated economic wind potential we report, the qualitative conclusions related to the importance of coal's operational flexibility would not be expected to change.

Discussion

Our base case estimate of available grid-connected wind potential in 2030 (2.6 PWh/yr) translates into capacity installations up to 930 gigawatts (GW), significantly larger than China's current unofficial target of 400 GW[10]. If China is able to realize this potential, wind could deliver nearly three-fourths of China's 2030 non-fossil primary energy target of 20%, a central part of China's national climate change strategy and commitment to global climate change mitigation (for full calculation, see SI Section 7).

Once curtailment and its associated cost penalty are considered, our results suggest that contrary to current plans, wind is not most cost-effectively installed in China's wind rich areas (the NW and NE) but instead should be located closer to load centers. While indicative plans from the grid company initially target 25% of wind capacity each in the NW and NE, respectively, our results using the lowest cost threshold (0.5 yuan/kWh) are only 14% and 17%, respectively. We find more economic potential in SH (closer to demand centers) at 58% of capacity and 56% of generation, with these shares dropping as we exploit more expensive wind resources in distant locations: 50% of capacity and 51% of generation at our base cost (0.6 yuan/kWh), and 48% of capacity and 50% of generation at the highest cost (0.7 yuan/kWh). Our results underscore the fact that failing to consider the grid integration step—specifically, the interaction of available wind resource with the electricity supply mix and demand profiles across regions—when developing national blueprints for the spatial distribution of future electricity capacity can yield vastly different recommendations for planning. Integration cost should not be overlooked.

Coal flexibility, which encapsulates both minimum generation output and the ability for intra-day startup, shutdown and ramping, introduces the substantial uncertainty into estimates of grid-integrated wind potential. Reducing cycling times through "hot-starts", better and more frequent commitment scheduling, and lower minimum generation set points are promising options for increasing operational flexibility (see SI Section 4.3.1). The interaction of wind with CHP technologies that carry district heating requirements, particularly prominent in the NE, will be more challenging to address, with heat storage and electric boilers representing potential sources of flexibility. In a flexible coal scenario, grid-integrated potential reaches 3.1 PWh, or 18% more than the base case, further raising the contribution of wind to achieving China's non-fossil energy target.

However, because efficiencies and emissions intensities of thermal power plants are not constant, it is difficult to assess precisely the CO_2 and other emissions reductions possible with enhanced flexibility. These reductions depend on the operational profile, in particular, on the degree of cycling (changes in output and startup/shutdowns) and the steady-state loading (with lower outputs typically less efficient). At the high wind penetrations (~30%) considered in this analysis, prior research suggests that achieved carbon dioxide emissions reductions may be only 80% of those expected ignoring these effects, with local pollutant emissions reductions likely to be eroded further[11].

We consider the potential benefits of energy storage, simulating a scenario in which region-specific pumped hydro storage is available following previous analysis[10]. We allow storage to charge whenever excess wind is available and then allow storage to deliver electricity to the system whenever net load exceeds minimum base load until available stores are depleted. We find that adding storage to the base case can increase grid-integrated economic wind potential by 2% to 8%, with the lower bound reflecting a fixed generation profile and the upper bound fully endogenizing wind site selection to account for storage availability (see SI Section 4.3.2). We also test sensitivity to demand response programs designed to enhance system flexibility at peak times by shifting demand. We find that demand profiles that achieve a reduction in peak demand of 5% can increase wind potential by around 7%, though much of these benefits are captured by more frequent and flexible coal generator scheduling (SI Section 4.3.3). We further explore sensitivities to coal cycling costs (SI Section 4.3.4), combined heat and power (CHP) system growth (SI Section 4.3.5), and UHV transmission costs (SI Section 4.3.6), and find modest impacts on estimates of grid-integrated wind potential.

While our projection is consistent with estimates of new coal capacity that incorporate planned and permitted coal plants, we note that there is substantial uncertainty associated with future projections of electricity demand in China. Our wind integration results roughly scale with demand (SI Section 4.3.8), though they are not highly sensitive to potential overcapacity in the coal fleet. China's policies target a reduction in the share of coal in primary energy and in the electricity sector in the coming years, and this target is expected to be robust to any adjustments in projections of electricity demand. Our projections also reflect existing plans for natural gas expansion in electricity. Expansion has proceeded less rapidly than envisioned in recent years. If this situation continues, it would further reduce flexibility and grid-integrated wind potential in China's future electricity system, relative to estimates reported here.

Our calculation of wind's potential contribution to China's 2030 non-fossil energy target depends on demand growth and energy use throughout the economy, for which we rely on government forecasts and relevant modeling studies. Should energy-intensive industries fall as a share of total demand, the generally larger variations in tertiary and residential sector demand could heighten wind integration challenges, raising the importance of introducing system-wide flexibility. While wind penetration potential is roughly constant across electricity demand forecasts, a reduction in total demand would decrease wind's contribution to grid-integrated electricity and economy-wide targets. Another important uncertainty is the willingness to pay for wind electricity as determined by policy makers when setting the feed-in tariff, which in our base case is comparable to current FITs (ignoring system-wide balancing costs). If the government reduces or withdraws policy support, wind development could slow substantially.

Importantly, utilizing wind at a large scale in 2030 will require not only deployment of wind capacity, which is currently directly incentivized, but the adjustment of power sector operations to reduce curtailment and increase flexibility. A potential step could be to abolish coal must-run quotas or lower them to non-binding levels. This step must be taken together with a broad reshaping of the operational rules and norms that govern the electric power system to ensure all generation options can take advantage of the increased flexibility. Electricity storage technologies, more flexible generation options such as natural gas and demand-side adjustments, and greater inter-regional transmission could contribute to maximizing grid-integrated wind. Intra-regional integration bottlenecks – including inter-provincial interconnection and electricity exchange mechanisms – will need to be addressed to realize estimated potentials (see SI Section 6.2).

A more complex, systems-level challenge will involve aligning the incentives of multiple stakeholders (generation companies, grid managers and government officials) to ensure that wind deployment decisions are based on integration constraints and costs in addition to current practice of considering resource quality, economics, and other factors. We recognize that cost considerations are far from the only determinant of the placement of energy infrastructure[12]. Our analysis of cost-optimal placement can reveal the incremental cost associated with selecting less attractive locations first, for political or other reasons. Importantly, our results underscore that increasing the contribution of wind to China's electricity mix will require much more than policies that promote wind farm construction in wind-rich areas and feed-in tariffs to support its utilization. More fundamentally, changes to system design and operation that increase overall flexibility—a much more challenging task that requires coordination among stakeholders involved in planning, dispatch, and transmission to recognize and mitigate integration cost penalties—will be required to unlock wind's greatest potential.

Materials and Methods

Physical Resource Assessment

The physical assessment of wind resources for this study is created using Modern Era Retrospective-analysis for Research and Applications (MERRA) boundary layer flux data, a thirty-seven-year (1979-2015), high temporal resolution (one hour) dataset with cells of 0.5°

latitude by 0.67° longitude spatial resolution (approx. 56 km × 61 km at mid-latitudes) [13]. It is constructed using boundary layer similarity theory and the Goddard Earth Observing System (GEOS-5) Atmospheric Data Assimilation System, consisting of the GEOS-5 model and interpolation analysis methods[14]. All wind power densities are calculated using 80-meter hub height Sinovel 1.5-MW (onshore) and 120-meter hub height Sinovel 5-MW (offshore) turbine power curves.

Following previous work[4,15] certain geographic features such as forests, water bodies, high elevation areas, steeply sloped areas (>10%) and urban areas are considered unavailable for turbine siting. Environmental protection areas are also excluded. An exclusion map of locations unavailable for wind turbine siting was constructed in the ArcGIS platform using 30-arcsecond elevation data from NASA's Shuttle Radar Topography Mission[16], a land-cover classification for China using satellite remote-sensing[17], and protected areas classified by the United Nations Environment Programme[18]. As remote-sensing land cover may have some errors in classifying land use, we tested the robustness of our forest cover maps results through comparison with the global vegetation classification scheme of NASA's Moderate-Resolution Imaging Spectroradiometer (MODIS) [19]. Total physical potential increased by roughly 5%, but grid potential was unchanged. We base turbine spacing parameters on available Chinese project data (see SI Section 1) and experimentally observed power reductions with turbine spacings of up to 10 rotor diameters[20], in the base case allowing 0.58 km^2 area per turbine, or roughly 9×9 rotor diameter spacing. Overly dense turbine spacing can lead to turbulent wake effects on downwind turbines and affect the total estimated wind generation.

Economic Resource Assessment

We employ a levelized-cost-of-electricity (LCOE) approach to calculate for each grid cell the break-even tariff at which the net present value (NPV), properly discounting future cash flows against upfront costs, is zero for a wind farm[*]. Similar to the procedure applied in[4], we construct a supply curve for wind, with the distinction that we plot grid-integrated economic potential, which includes reserve and ramping as well as curtailment costs. Our approach adds

[*] Though widely used, it has been argued that LCOE is an imperfect metric for intermittent resources and that a superior method would compare generation options on the basis of economic value by computing the market price times generation in each time step[21]. With the absence of a competitive wholesale electricity market, China's case is analyzed here in terms of estimates of system-wide costs.

detail on the components of cost as well as the extent of resource available with a given cost structure (captured by the width of each bar). The supply curve shown in Figure 3 identifies the sequence of grid cells slated for wind deployment at various LCOE thresholds. A comparison with[4] is shown in SI Figure S11.

The calculation assumes that current Chinese financial regulations for wind projects remain unchanged. The total NPV of a project includes all costs and revenues, as well as pre-determined required rate of return on equity investment and loan debt. We use the associated cell-specific capacity factor to determine the LCOE (threshold price at which turbine construction becomes financially feasible) for each 0.5° by 0.67° grid cell.

Capital costs are covered by a combination of equity investment and debt from financial institutions. In order to reduce their internal capital contribution, developers typically minimize the share of their own equity investment subject to the minimum requirement, which we set at 20%. We assume wind projects require an internal rate of return of 10%.

Currently, there are four levels of feed-in tariffs ranging from 0.47-0.60 yuan/kWh ($0.072-0.092) for on-shore wind projects in China[22]. This paper assumes that the sale price of a wind power project will remain constant during its lifetime, a typical assumption used in investment decisions. For offshore wind projects, the electricity tariff is currently determined by a concession bidding process[†].

Electricity Dispatch Model

Wind integration challenges arise from high variability and inaccurate wind forecasts interacting with transmission constraints and technical limits of conventional generators, such as ramping, startup and shutdown, and minimum stable output thresholds[23]. For example, large fluctuations in wind may occur over the span of a few hours – less than an acceptable startup/shutdown time for a typical 600 MW coal-fired power plant or nuclear plant. China's heavy reliance on coal-fired generation, a large fraction of which includes must-run combined heat and power plants in the north in winter, as well as institutional factors such as inflexible pricing and grid operation norms and procedures, exacerbate these challenges[24,25].

[†] China's first offshore pilot, Donghai Bridge in Shanghai, cleared with a concession price of 0.978 yuan/kWh, a level significantly higher than subsequent auctions and therefore was not used in the range of offshore tariffs in the present assessment.

For this study, we develop an economic dispatch model for China that can resolve hourly profiles of net load (demand minus integrated wind) that must be met by conventional generating units, calculate ramping and reserve costs, as well as expected wind curtailment due to must-run baseload units. Determining the appropriate hourly generation amounts by power plant, assuming centralized operation, is in general a mixed integer linear program (MILP) optimization problem known as unit commitment and economic dispatch, accounting for a range of techno-economic criteria. To improve tractability, expansion planning models may relax the binary commitment constraints, optimizing over just continuous dispatch decisions, though this introduces approximation errors by overestimating the flexibility of generators. However, capturing generator-level detail would result in a linear program with variables numbering in the millions for a system as large as China's with conservatively 3,000 thermal power plants ignoring multiple units inside the fence. To find the optimal wind supply curve using these techniques would be computationally expensive and require plant-level data on operations, which is widely considered proprietary.

To address these difficulties, we develop an hourly dispatch model that simplifies the calculation of optimal dispatch through a heuristic that meets demand based on the probable ordering of a number of generation "layers". The heuristic considers must-run limits of base load generation, ensures sufficient reserves to meet peak load (plus a reserve margin of 5%) given regional generation mixes, calculates ramping and reserve costs, and can be iterated several thousand times on a personal desktop machine. A full description of the methodology used in the dispatch model can be found in SI Section 3. We aggregate demand and generation in four regions: Northwest China Grid (NW), Northeast China Grid (NE), "*SanHua*" (SH) referring to the combination of the East China Grid, Central China Grid and North China Grid, and the China Southern Power Grid (S). Two major inter-regional transmission pathways (NW-SH and NE-SH) are assumed, with costs based on current ultra-high voltage (UHV) transmission projects.

We advance on traditional planning models that use "screening curve" approaches by allowing endogenous selection of non-dispatchable wind capacity, consideration of seasonal differences in the availability and must-run capacities of different generation types, and calculation of inter-hourly ramping and associated constraints.

Besides wind, four main technologies, in dispatch order from base to peaking functions, are in wide use in China today: nuclear, hydro, coal/biomass (hereafter, simply coal) and natural gas. Since large fluctuations in wind may occur over the span of several hours, a fraction of coal and all of nuclear are designated must-run baseload units. In our main analysis, we do not simulate the interaction of multiple intermittent renewable energy types on the grid. In a sensitivity case reported in the SI Section 4.3.7, we test the impact of expanded solar capacity in accordance with ambitious projections of 350 GW. Assuming solar receives priority grid access, we find wind curtailment increases by 16-53%. That is, effectively 70% of additional renewable energy generation from solar is curtailed.

Integration of intermittent energy depends on its correlation with demand, which varies by region and time of year. Annual demand profiles are estimated using typical seasonal hourly curves, scaled to daily consumption totals in 2012-2013, and extrapolated to 2030 based on demand growth forecasts. Hourly curves are constructed for grid regions NE, NW, and SH by a weighted average of typical winter and summer provincial load profiles. For the South, we use a profile of Guangdong's electricity consumption to generate representative daily load curves for winter and summer. Provincial totals on a daily basis over 2012-2013[26] are then aggregated to regions and combined with hourly variations into a continuous 8760-hour demand curve. Finally, electricity consumption growth scenarios to 2030 at a regional level obtained from China's State Grid are used to scale from 2013 totals[¶]. A detailed description of this procedure is included in Section 3.2.2 of the SI.

The dispatch heuristic, developed in MATLAB, proceeds as follows: a demand array is partitioned hourly into the four generation layers, proceeding from 0 to the max layer capacity in the following order: 1) nuclear + must-run coal, 2) hydro, 3) remaining coal, 4) natural gas. Nuclear, coal, gas and hydropower capacity were scaled by 100%, 90%, 90% and 40%, respectively, to represent average combined availability and capacity factor. Seasonality of hydropower generation is represented in the base case by scaling monthly generation to historical averages preserving an annual capacity factor of 40%. The fraction of must-run output from the coal-fired fleet is a critical input to the model, a function of the penetration of must-run CHP and

[¶] Electricity demand growth rates by region: NE: 91.2%, NW: 134.8%, S: 74.0%, SH: 74.0%. Authors calculations based on[10].

nuclear capacity, and minimum necessary committed coal units to ensure peak load is met given the generation mix.

Generation is zero for any layer if demand is less than the cumulative capacity below it. The difference in each layer's generation from hour to hour is equated to its ramp. Projected capacities by central grid planners for each grid zone in 2030 are shown in Figure 5.

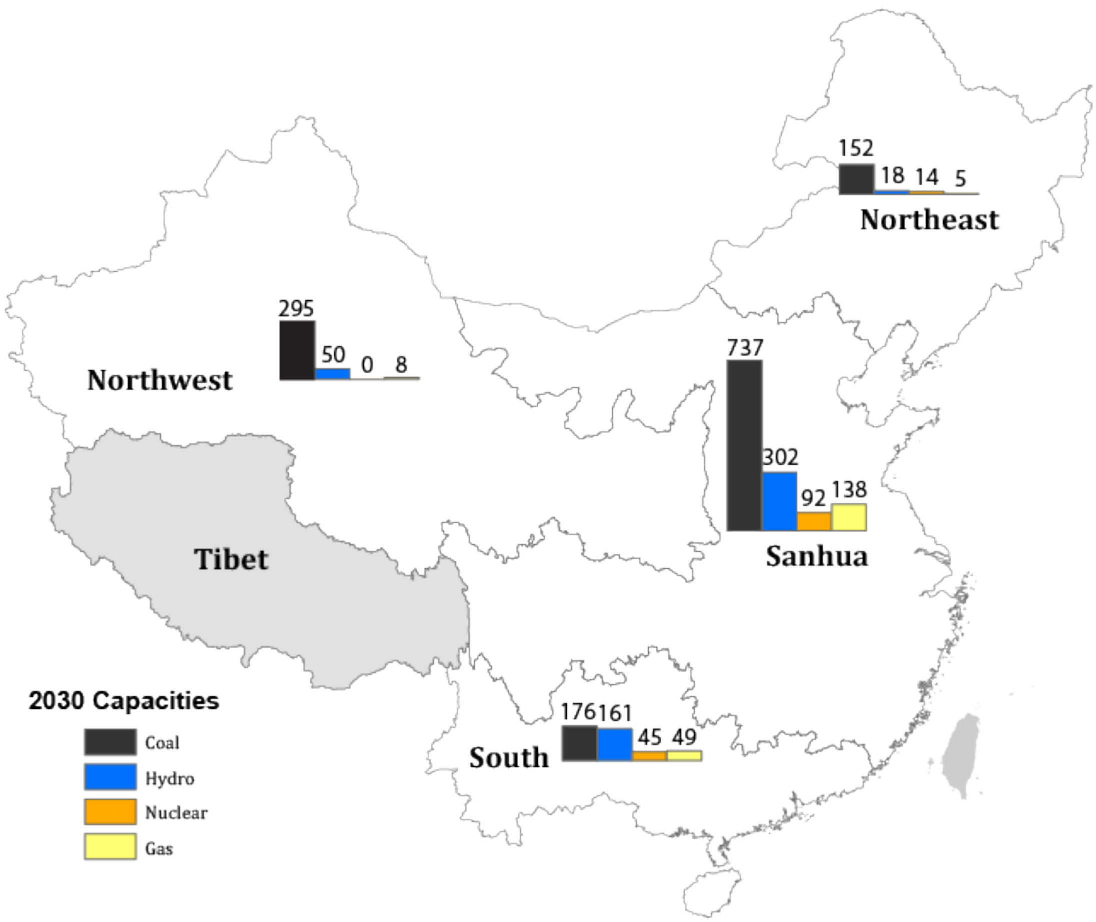

Figure 5. Four grid regions and projected 2030 capacities for non-renewable generation (in GW) used in this study (Tibet is excluded as data is not available).

When wind produced in each cell is added to the system, net load (the difference between load and wind, equivalent to the load that must be met by conventional units) decreases non-uniformly across hours, causing changes in the generation and ramps by layer. All wind that pushes net load below the must-run base load capacity is assumed curtailed. This is represented by a proportional reduction in output from that cell, thereby increasing the average cost of wind from the cell (in LCOE terms). A single year (2009) of wind resources, representing a central case for average annual capacity factors over a rectangular region containing China, is used to estimate the hourly variation in wind resources. Using the 2007 wind profile, which is the 37-year minimum for capacity factors over the region, reduced potential by 5%.

Finally, reserves are procured to meet wind forecast errors, with costs depending on the generation type. A reserve requirement of 15% of total wind penetration is used in the base case (with sensitivities described in SI Section 3.2.3). Integration penalties of a given wind profile are thus characterized by integration costs (ramping and reserve costs) and curtailment.

Our method may introduce approximation errors compared to actual system operation by neglecting startup constraints outside of the base layer, cost and emissions penalties associated with low loading, and the heterogeneity of plants within layers (described further in SI Section 3.1.6). The dispatch model cannot resolve the individual discrete decisions to commit thermal units, causing it to underestimate inflexibilities and integration costs in higher layers. Conversely, the must-run thresholds that approximate minimum outputs to provide heating, reliability and other services, may overestimate inflexibility in the base layer where "hot starts" and improved commitment scheduling could have a large impact.

Increasing flexibility in operation of coal plants is possible, and can include reduced cycling times through "hot starts", better commitment schedules as well as lower minimum generation outputs of coal units. To illustrate the potential of these improvements to enhance wind integration, we test a range of scenarios referred to as *CoalRigid* and *CoalFlex*. In the latter, we relax current operational practice that mandates coal units are committed for at minimum one week, and instead require that all reserves are sufficient to meet peak load over 8-hour periods (full results are reported in SI Section 4.3.1).

The coal flexibility scenario ranges are informed by validation of model-predicted curtailment with observed curtailment in two regions in 2013 (for validation results see SI Section 6.1). We expect our model to under-predict observed curtailment—especially over multiple provinces—because of inflexible planning mechanisms influencing wind integration and intra-regional transmission congestion. Our analysis assumes these constraints will be largely relieved by 2030 given current electricity reform plans and network expansion goals, which we show are sufficient to relieve intra-regional congestion in SH induced by aggregating three different grid regions (SI Section 6.2). Our results caution that if current plans do not materialize, within-region wind integration could become further restricted.

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Figure Legends:

Figure 1. Wind capacity factors (white areas are unsuitable for wind farm construction and excluded from the analysis).

Figure 2. Base case estimates of onshore and offshore wind potential in this study, compared with previous studies.

Figure 3. Supply curve of grid-integrated wind in the base case, with generation, integration, transmission and curtailment costs (if applicable). NW – Northwest, NE – Northeast, S – South, SH – *SanHua* (shaded regions are offshore). GenCost – generation cost, TransCost – UHV transmission cost, ReRaCost – reserve and ramping costs, TransCurtCost – curtailment cost due to transmission capacity limit, CurtCost – curtailment cost due to integrated region's generation mix.

Figure 4. Sensitivities of grid-integrated economic wind potential to assumptions on turbine spacing, capital cost, operating and maintenance (O&M) cost, ramping and reserve cost, ultra-high voltage (UHV) transmission cost, and operational flexibility of coal generation.

Figure 5. Four grid regions and projected 2030 capacities for non-renewable generation used in this study, also in Table 1 (Tibet is excluded as data is not available).