ACHIEVING AN 80% CARBON FREE ELECTRICITY SYSTEM IN CHINA BY 2035

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TABLE OF CONTENTS

1 EXECUTIVE SUMMARY

Dramatic reductions in solar, wind, and battery storage costs create new opportunities to reduce emissions and costs in China's electricity sector, beyond current policy goals. China's current goals would lead to a 60% share of non-fossil fuel electricity generation by 2035, an increase from 34% in 2020. This study examines the cost, reliability, emissions, public health, and employment implications of increasing the share of non-fossil generation in China to 80% by 2035. Achieving an 80% share of non-fossil fuel, carbon free electricity generation by 2035 might better position China to meet its 2060 goal for carbon neutrality, given the electricity sector's importance in economy-wide decarbonization.

The study aims to inform discussion around two questions. First, what do recent declines in wind, solar, and battery storage costs imply for the optimal pace and scale of the development of these resources over the next 15 years in China? Second, what are technically and economically feasible 2035 goals for non-fossil fuel electricity generation, in the context of China's transition to carbon neutrality by 2060?

Our study is based on detailed modeling of China's electricity systems, and their impact on the economy, employment, and public health. The study's electricity analysis uses state-of-the-art capacity expansion and hourly dispatch models (PLEXOS), focused on the years 2025, 2030, and 2035. The models are based on a detailed representation of China's electricity system, including hourly provincial loads, interprovincial and interregional transmission constraints, region-specific wind and solar profiles, and recent (2021) renewable energy and electricity storage cost projections for China. The analysis' electricity demand projections are based on the 1.5°C scenario in Tsinghua University's 2020 *Low Carbon Development Strategy and Transition Roadmaps Study*, capturing expected changes in China's electricity demand needed to meet a global 1.5°C warming target.

The study considers two main scenarios: a Current Policy scenario, in which the annual deployment of wind and solar generation is limited to current government goals; and, a Clean Energy scenario, in which the share of non-fossil generation in China rises to 80% in 2035. Several sensitivity cases test variations on the Clean Energy scenario, focused on system reliability.

In both scenarios, wind and solar generation are the lowest cost and most scalable non-fossil generation resources. In the Current Policy scenario, combined wind and solar generation capacity is consistent with the government's goal of 1,200 GW by 2030 and rises further to 1,943 GW by 2035; the share of non-fossil generation is aligned with the government's goal of 50% by 2030 and rises to 60% by 2035 (Table 1). In the Clean Energy scenario, wind and solar generation capacity nearly achieves the current 2030 target in 2025 and rises to 1,994 GW in 2030 and 3,069 GW in 2035; the share of non-fossil generation rises to 65% by 2030 and 80% by 2035. Electricity storage capacity increases rapidly in both scenarios, due to continued declines in battery costs and assumed policy support for pumped hydropower.

TABLE 1. *Key Differences in the Current Policy and Clean Energy Scenarios*

METRIC	YEAR	CURRENT POLICY SCENARIO	CLEAN ENERGY SCENARIO
Change in coal generation relative to 2020	2025	4%	-7%
	2030	0%	-32%
	2035	-12%	-56%
Non-fossil generation share	2025	40%	46%
	2030	49%	65%
	2035	60%	80%
Coal capacity	2025	1,189 GW	1,049 GW
	2030	1,199 GW	1,049 GW
	2035	1,199 GW	1,049 GW
Wind and solar generation capacity	2025	873 GW	1,153 GW
	2030	1,273 GW	1,994 GW
	2035	1,943 GW	3,069 GW
Battery storage capacity	2025	98 GW	155 GW
	2030	225 GW	356 GW
	2035	244 GW	414 GW

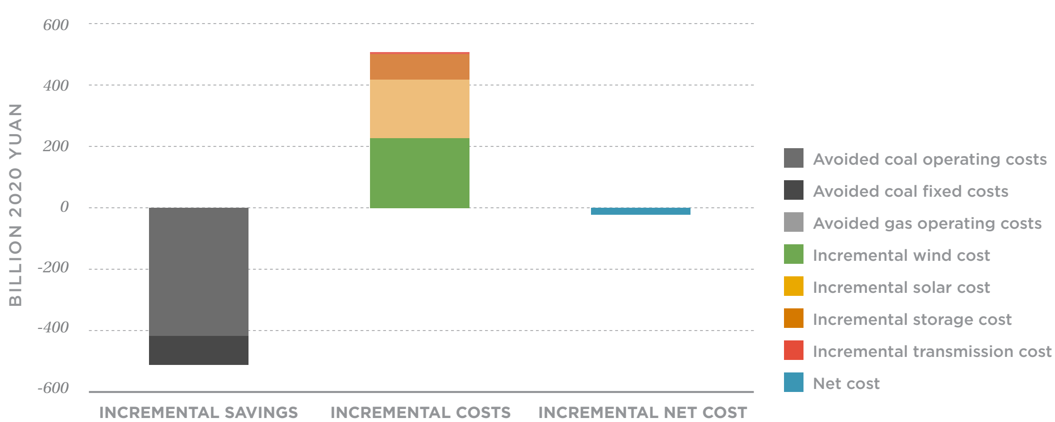
In the Current Policy and Clean Energy scenarios, non-fossil generation accounts for almost all new generating capacity. The Current Policy scenario includes a net addition of 150 GW of coal generation capacity, assuming that some coal generating units that are currently under construction are built. The Clean Energy scenario assumes that this net 150 GW of coal generating capacity is not added to the generation mix. The model is constructed and enabled to build additional new coal generating capacity for economic reasons, but does not do so in either scenario. This result suggests that, in both scenarios, a portfolio of new non-fossil generation and energy storage is lower cost than new coal generation to meet growth in electricity demand.

The Current Policy and Clean Energy scenarios differ primarily in the operation of existing coal generation. In the Clean Energy scenario, additional wind, solar, and battery storage displace a significant amount of generation from existing coal plants to meet non-fossil generation targets. In the Current Policy scenario, generation from existing coal plants declines by only a small amount by 2035, relative to 2020 levels. Both scenarios assume no retirement of existing coal generation, though coal retirements are considered in a sensitivity case.

Wholesale generation and transmission costs are lower in the Clean Energy scenario than in the Current Policy scenario. The reason for this result is that the incremental cost of new solar, wind, battery storage, and transmission in the Clean Energy scenario is lower than the operating (fuel and O&M) and fixed costs of fossil fuel generation – mostly coal fuel costs – avoided relative to the Current Policy scenario (Figure 1). This result suggests that enabling more rapid deployment of wind and solar generation, from a historical high of 120 GW per year in 2020 to an average of 215 GW per year between 2030 and 2035 in the Clean Energy scenario, would reduce wholesale electricity costs.

FIGURE 1. *Incremental Cost Savings, Incremental Costs, and Incremental Net Costs in the Clean Energy Scenario, Relative to the Current Policy Scenario*

2035 INCREMENTAL SAVINGS, COSTS, AND NET COST



Reaching an 80% non-fossil generation target by 2035 would generate additional emission reductions and public health benefits. Relative to the Current Policy scenario, the Clean Energy scenario reduces electricity sector CO_2 emissions by 50% (by 1,660 $MtCO_2$) and mortality from exposure to fossil fuel power generation emissions by 47% (around 50,000 avoided premature deaths) in 2035. Electrification will increase these benefits by reducing emissions from primary fossil fuel consumption in the transportation, industry, and buildings sectors. In tandem, rapid increases in non-fossil generation and electrification can be a powerful and potentially low-cost approach to accelerate progress toward China's carbon neutrality and air quality goals.

Significant reductions in coal generation in the Clean Energy scenario correspond to continued declines in demand for coal and a reduction in employment in the coal mining sector. This study projects that these losses in coal sector employment are, however, largely offset by increases in employment in other upstream electricity industries due to large-scale investments in wind, solar, and storage, and by increases in economy-wide employment due to reductions in wholesale electricity costs. Even if the overall change in employment is net positive, however, managing the labor and fiscal implications of a 50% reduction in the electricity sector's coal consumption will present significant challenges and warrants careful planning and national-level support.

In the Clean Energy scenario, onshore wind, offshore wind, and solar PV generation combined reach 60% of total generation in 2035.[1] There are longstanding questions in China as to whether it would be possible to operate electricity systems with such high penetrations of variable renewable generation. As a sensitivity, in this study we examined whether the resource portfolio in the Clean Energy scenario could reliably meet summer and winter electricity demand during the two highest net load (load minus wind and solar generation) weeks of the year in 2035, accounting for load forecast error and using 35 years of simulated weather data to account for wind and solar forecast error. The results suggest that the system would be able to reliably meet demand, while maintaining a 10% operating reserve margin. We also examined the reliability implications of retiring existing generation, and find that up to 250 to 300 GW of existing coal generation could be retired without affecting reliability.[2]

Enabling more rapid deployment of wind, solar, and electricity storage capacity may require several changes in policy and regulation, which we organize into three areas: policy targets, markets and regulation, and land use. Table 2 describes recommendations for changes in each area, based on the results of this study. These recommendations aim to provide guidance to manufacturers and the electricity industry, create stable business models for renewable generation and electricity storage, integrate renewable generation and storage at low cost, ensure electricity system reliability, and minimize the land use impacts of large-scale wind and solar development.

1 Nuclear power and hydropower account for the remaining 20% of non-fossil fuel generation's 80% share of total generation in this scenario.

2 The capacity expansion model builds a significant amount of battery storage for energy arbitrage and pumped storage for policy reasons. With these additions, the capacity constraint in the capacity expansion model is not binding in 2035, suggesting that existing coal generation could be retired without affecting system reliability. We evaluate system reliability with different levels of coal retirements using a detailed dispatch model.

TABLE 2. *Policy Recommendations*

AREA	RECOMMENDATION
Policy targets	Increase 2025 and 2030 targets for renewable generation and energy storage capacity (GW).
	Set targets for the share of non-fossil generation in total energy (GWh) generation, for 2035.
Markets and regulation	Consolidate approaches to renewable energy procurement and focus on participation in forward contract markets.
	Continue progress in developing electricity spot markets and support their evolution into regional markets.
	Strengthen the renewable quota and green certificate system.
	Develop market participation models for electricity storage.
	Integrate distributed energy resources into wholesale markets.
	Develop formal, binding resource adequacy processes and mechanisms.
Land use	Prioritize land use efficiency.
	Integrate wind and solar development into land use and conservation planning.

Changes in markets and regulations would help to spur innovation and continued reductions in technology costs, supporting accelerated decarbonization in China's electricity sector over the next 15 years. Faster decarbonization in China's electricity sector would, in turn, allow electrification to support CO_2 emission reductions in other sectors on the country's path to a carbon neutral economy by 2060.

2 INTRODUCTION

This report examines the technical feasibility, costs, and implications of increasing the share of non-fossil fuel electricity generation in China to 80% of total generation by 2035. The analysis uses state-of-the-art modeling tools, detailed load, wind, and solar profiles for China, and recent projections for wind, solar, and electricity storage costs in China.

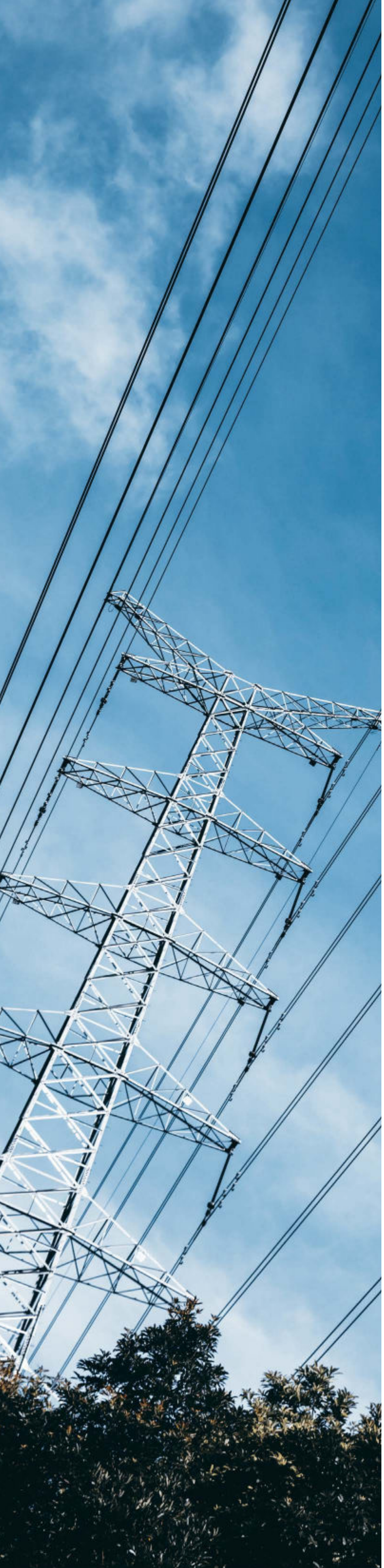
The report aims to inform discussion around two questions. First, what do recent declines in wind, solar, and battery storage costs imply for the optimal pace and scale of the development of these resources over the next 15 years in China? Second, what are feasible 2035 goals for non-fossil fuel electricity generation, in the context of China's transition to carbon neutrality by 2060?

The electricity sector will play a pivotal role in meeting China's environmental goals, including both the carbon neutrality goal and air quality goals. Increases in non-fossil generation, combined with electrification in the transportation, industrial, and building sectors, can generate significant reductions in emissions. To understand the magnitude of these benefits, this study also includes analyses of emissions and health impacts.

Increases in the share of non-fossil generation will offset coal generation, creating employment in the manufacturing and construction sectors to expand non-fossil generation but leading to a decline in employment in coal mining and other sectors with links to the coal industry. To understand the magnitude of these competing impacts, this study also includes an employment analysis, using an input-output modeling framework and national macroeconomic data for China.

The report is organized into four sections.

- **Section 3** provides an overview of methods used in the electricity, health impact, and employment analyses.
- **Section 4** describes two categories of results: (1) changes in generation and transmission, and (2) cost, investment, emissions, reliability, health impacts, and employment impacts.
- **Section 5** summarizes key conclusions from the study, provides policy recommendations, and outlines priority areas for future research.
- **Appendices** provide more detailed information on the modeling approach, data inputs and sources, load shape development, and wind and solar profile development.



3
METHODS

This study draws on intensive scenario building, data development, and power system modeling using detailed, best-available data inputs and state-of-the-art modeling tools. This section provides a brief overview of scenarios, key inputs and assumptions, modeling tools and approach, and sensitivity analyses. The study appendix includes detailed descriptions of methods for the modeling and the development of hourly load, wind, and solar profiles.

3.1 SCENARIOS

The analysis examines two core scenarios: a Current Policy scenario, which is consistent with current policies and technology cost trends in China; and, a Clean Energy scenario, in which 80% of China's electricity is generated using non-fossil fuel resources in 2035. Sensitivity analyses explore variations on the Clean Energy scenario (Section 3.4).

The Current Policy and Clean Energy scenarios differ in three assumptions (Table 3). First, in the Current Policy scenario, we force a net 150 GW of coal generation additions into the model, based on plants currently under construction and some retirement of existing generation.[3] In the Clean Energy scenario, we do not force this net 150 GW of coal generation into the model. In both scenarios, the model can build new coal generation as part of least-cost capacity expansion.

3 Based on existing policies and planned coal projects, we include a net 150 GW of new coal generation capacity through 2030. This is consistent with estimated net new additions of 158 GW through 2030 without additional measures from Cui et al. (2022).

TABLE 3. *Description of Scenarios*

	CURRENT POLICY SCENARIO	CLEAN ENERGY SCENARIO
Coal generation capacity additions	150 GW of new net coal generation is forced into the model	No new net coal generation is forced into the model
Wind and solar generation capacity additions	Annual wind and solar generation capacity additions are limited to policy targets (1,200 GW total wind and solar capacity by 2030)	Annual wind and solar generation capacity additions decided by model to meet 80% clean electricity by 2035
Non-fossil generation share	Least-cost optimization, subject to limits on non-fossil generation additions	46% in 2025; 65% in 2030; 80% in 2035

Second, the Current Policy scenario assumes that the amount of new wind and solar generation that can be added in any given year is limited in each model year to meet current policy targets and their implied trajectories in 2035. In the Clean Energy scenario, these limits are relaxed and new wind and solar generation capacity additions are instead driven by annual targets for non-fossil generation. Lastly, in the Current Policy scenario, the amount of total non-fossil generation is calculated through least-cost optimization in the model, subject to limits on wind and solar capacity additions and policy targets for nuclear power and hydropower. In the Clean Energy scenario, the model builds non-fossil generation to meet the following non-fossil generation targets: 46% in 2025, 65% in 2030, and 80% in 2035.

3.2 MODELING TOOLS AND APPROACH

The electricity system analysis was conducted using PLEXOS, a modeling platform that is widely used for industry-standard power systems analysis. The modeling used a two-stage approach. In the first stage, we used PLEXOS' capacity expansion tool to develop least-cost portfolios for each scenario, subject to model constraints. In the second stage, we used PLEXOS' production simulation tool to examine operating costs, emissions, and reliability for each hour over the course of each model year. Our dispatch modeling is limited to DC power flows; it does not consider the more complex dynamics of AC power systems.

Our representation of China's electricity system in PLEXOS included a detailed rendering of generation resources, generation constraints, unit commitment, and interprovincial and interregional transmission constraints. Figure 2 shows the location of transmission and generation capacity in the Clean Energy scenario, illustrating the level of spatial detail included in the model. We represent the Chinese electricity grid using 32 interconnected nodes, connected using 182 inter-provincial transmission corridors. We assume that the electricity system is balanced and reserves are managed at a regional grid scale, enabling efficient resource sharing among provinces.[4]

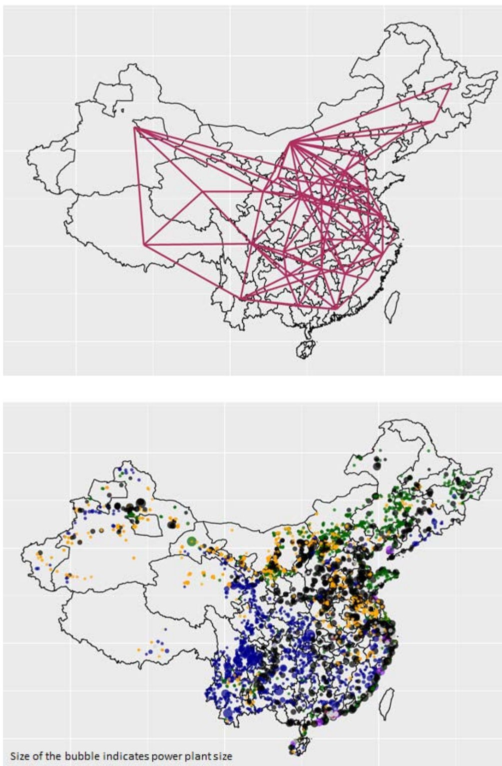


FIGURE 2.
Base Year (2020) Generation Resources and Transmission Network Included in the Modeling

The study's health and employment impact analyses were conducted using outputs from the PLEXOS modeling. The health analysis used an adapted reduced-form air quality model, InMAP (Intervention Model for Air Pollution). The employment analysis used Energy Innovation's China Energy Policy Simulator (EPS), an open-source model that includes an input-output (I-O) framework and uses China's

4 The model includes six regional grids: Northwest (Xinjiang, Gansu, Qinghai, Ningxia, Shaanxi, Tibet), Northeast (Liaoning, Jilin, Heilongjiang, East Inner Mongolia), North (Beijing, Tianjin, Hebei, Shanxi, Shandong, West Inner Mongolia), Central (Hubei, Hunan, Jiangxi, Henan, Sichuan, Chongqing), East (Shanghai, Jiangsu, Zhejiang, Fujian, and Anhui), and South (Guangdong, Guangxi, Guizhou, Hainan, Yunnan).

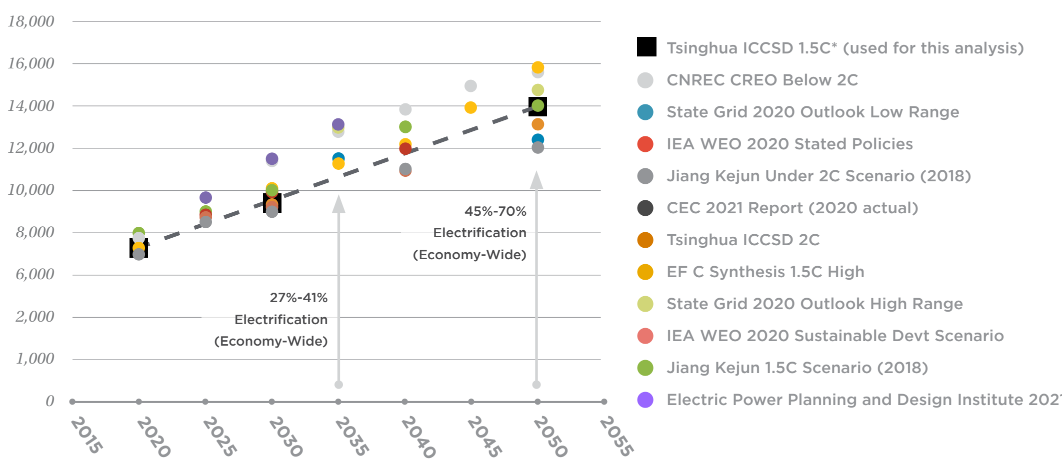
national income accounts and labor statistics.[5] The model measures differences in employment between the Current Policy scenario and the Clean Energy Scenario, calculated in job-years, or one year of employment. Appendix E describes the models and approaches used in the health and environmental impact analyses.

3.3 KEY MODELING INPUTS

Electricity Demand. Growth in China's electricity demand over the next 15 years is highly uncertain. It will depend on the structure and pace of economic growth and the pace of electrification in the transportation, industry, and buildings sectors. In this study, we based our electricity demand projections on the 1.5°C scenario in Tsinghua University's 2020 *Low Carbon Development Strategy and Transition Roadmaps Study*, which captures expected changes in China's electricity demand needed to meet a global 1.5°C warming target.[6] Figure 3 shows electricity demand projections used in this study relative to projections in other recent studies.

FIGURE 3. *National Electricity Demand Projection Used in This Study, Relative to Other Recent Studies*

CHINA ELECTRICITY DEMAND PROJECTIONS (TWH)



Sources: Jiang et al. (2018); ICCSD (2020); IEA (2020); SGERI (2020); CNREC (2020); CEC (2021a); Fu et al. (2020).

5 EPS is an open-source system dynamics computer model developed to inform policymakers and regulators about which climate and energy policies will reduce greenhouse gas emissions most effectively and with the most beneficial financial and public health outcomes. To calculate employment impacts, we used the model outputs from the two scenarios as inputs into the EPS jobs module alongside data on employment, wages, and labor productivity growth rate in China. The module then calculates relative employment impacts of the two scenarios via an input-output macroeconomic model by determining the impact of policies on individual industries, sorted by International Standard Industrial Classification (ISIC) codes. Full documentation of the mechanics of EPS's jobs module is available online. See Energy Innovation (2022).

6 ICCSD (2020).

Drawing on publicly available provincial electricity demand data, we converted national annual electricity demand into 31 provincial hourly load shapes (see Appendix C), which matches the hourly timescale used in the PLEXOS modeling. Our approach assumed that provincial system load factors decline over time, resulting in a national coincident peak demand (1,992 GW in 2035) that grows just over 1.5 times faster than energy demand during the next 15 years.[7]

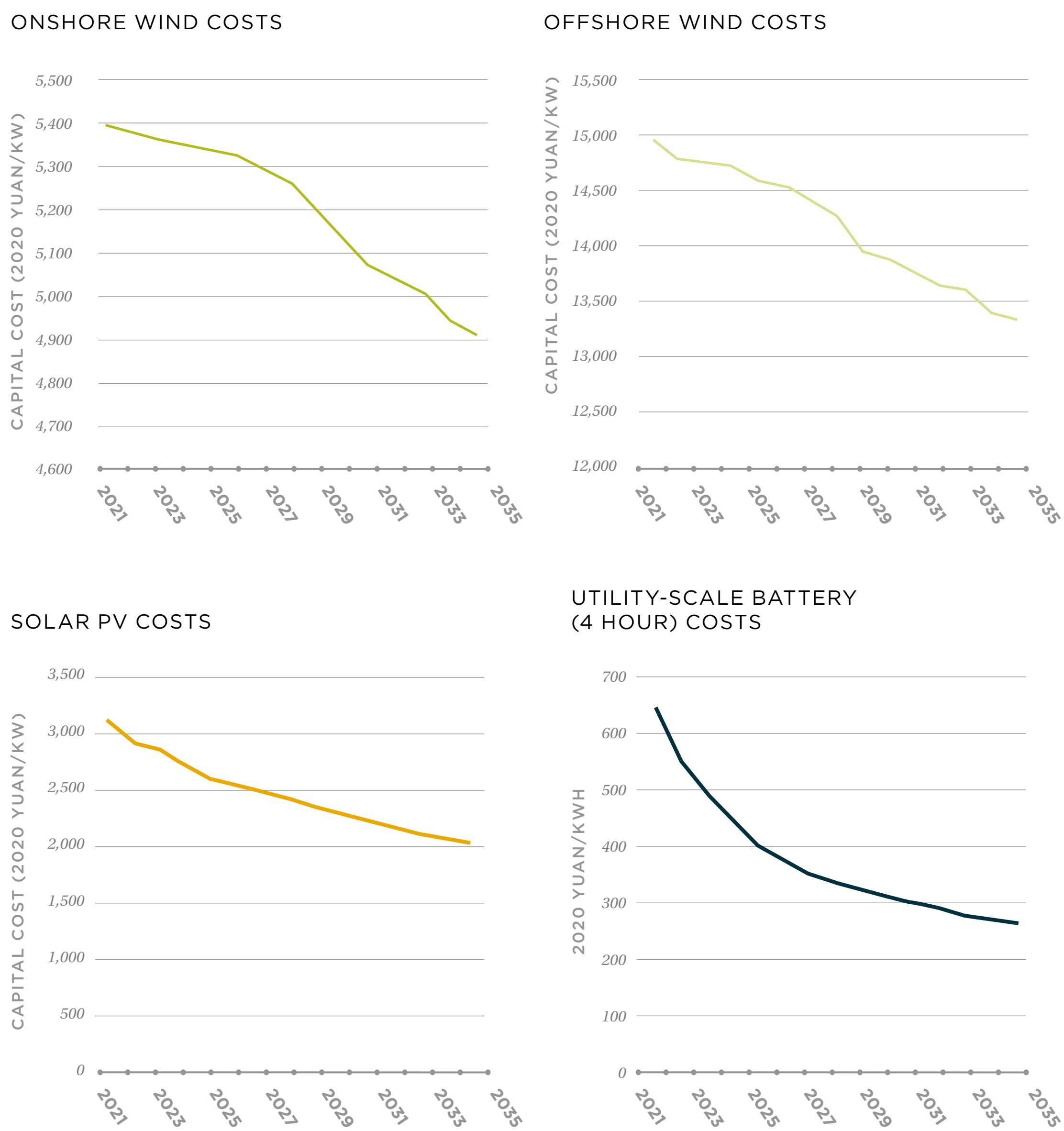
Technology and Fuel Costs. The PLEXOS model requires extensive resource cost inputs, among which the most important are wind, solar, and battery storage technology costs and coal fuel costs.[8] The analysis used projections of installed costs and fixed operations and maintenance (O&M) costs for onshore wind, offshore wind, solar PV, and 4-hour battery storage in China from Bloomberg New Energy Finance (BNEF), shown in Figure 4. The model also considers 2-hour and 8-hour duration battery storage; cost declines for these technologies are similar to those for the 4-hour battery shown in Figure 4. In cost and technology inputs, we do not make an explicit distinction between distribution- and transmission-connected resources.[9]

7 System load factor is the ratio between average and peak electricity demand. Declines in system load factor are consistent with reductions in the share of industrial electricity demand, which is consistent with recent trends in China. For capacity expansion, the modeling assumes a 15% planning reserve margin. The analysis does not attempt to incorporate changes in load shapes that would result from electrification or more responsive demand; this is an important area for future research.

8 We included several technologies in the capacity expansion analysis: coal generation, gas generation, large-scale hydro generation, nuclear generation, solar generation, onshore and offshore wind, 2/4/8-hour battery storage, and pumped hydropower storage. For simplicity, the analysis does not include biomass generation, concentrated solar power (CSP), or geothermal. These resources have challenges around cost-effectiveness and scalability.

9 Because we do not model intra-provincial transmission, from the perspective of the model, distribution- and transmission-connected resources look the same from an operational perspective. We did not have sufficient detail on land costs and incremental distribution and transmission costs to more meaningfully assess the tradeoffs between utility-scale and distributed resources.

FIGURE 4. *Technology Cost Inputs for Offshore Wind, Onshore Wind, Solar PV, and Battery Storage (4-hour)*



Source: Data are from BNEF (2020), converted using current exchange rate of 6.34 yuan/USD.

Longer-term coal price trends in China are highly uncertain. Coal prices rose to record levels in 2021 but are expected to moderate over time. Lower coal demand, consistent with national policy and the results of this study, would tend to decrease prices, but lower prices would tend to reduce supply, keeping prices closer to marginal production and transport costs. In this study, we assume that provincial thermal coal prices remain constant in real 2019 yuan terms over the study horizon, which means that coal prices increase at the rate of inflation.

The Current Policy and Clean Energy scenarios use the same technology cost and fuel cost assumptions. Appendix B provides detailed documentation of all generation and transmission technology and fuel cost inputs.

Solar and Wind Profiles. For this study, we estimated wind and solar resource potential and developed detailed solar and wind profiles for each province in China, using a two-part approach. First, we estimate the resource potential, or the maximum solar and wind capacity that can be installed in a province. We use average annual capacity factors from Global Wind and Solar Atlas and multiple exclusion criteria to estimate this potential. Exclusion criteria include elevation, slope, landcover, and ocean depth. Second, we develop detailed hourly generation profiles, using meteorological data from reanalysis datasets and simulating site level wind and solar generation using NREL's System advisor Model (SAM). Wind and solar farms can be designed in SAM and hourly generation can be estimated by passing meteorological data through it. We then use an aggregation algorithm to combine hourly generation from multiple sites in a province and create a representative province wind and solar resource profile. Complete methodology and data sources are discussed in detail in Appendix D.

Hydropower and Nuclear Generation. Hydropower and nuclear power generating capacity is often built for reasons other than underlying economics. For instance, flood control is often a primary driver of hydropower generation capacity. In this study, we fix the amount of conventional hydropower, pumped hydropower, and nuclear generation capacity to meet long-term policy targets rather than letting the model pick the least-cost amount of these resources. We assume that conventional hydropower, pumped hydropower, and nuclear generation capacities increase linearly from 2020 to meet long-term policy targets of 400 GW, 200 GW, and 100 GW, respectively, by 2035.[10]

10 2035 capacity values extrapolated from current policy targets for conventional hydro, pumped hydro, and nuclear from national energy plans and NEA (2021b).

3.4 SENSITIVITY ANALYSIS

The analysis considered three main sensitivities:

- **Coal retirements.** The two scenarios assume no retirements of existing coal generation. As a sensitivity, we manually retired coal units after an assumed 30-year lifetime, decreasing the amount of coal generation in each model year in both the capacity expansion and production simulation analysis.
- **Reliability.** The scenarios use deterministic wind and solar generation and load profiles. As a sensitivity, we assessed the robustness of the Clean Energy scenario portfolios to prolonged periods of low wind and solar generation and an unanticipated demand shock. To examine the reliability impacts of prolonged periods of low wind and solar generation, we ran PLEXOS for the highest net load week in the summer and winter in 2035, using 35 years of high spatial resolution wind and solar data for China (see Appendix D). To examine the reliability impacts of an unanticipated demand shock, we ran PLEXOS for the highest net load period during the summer and winter in 2035, assuming a 10% increase in demand above forecast.[11]
- **Offshore wind.** Offshore wind has potential to reduce higher-cost transmission and energy storage investment needs, by providing a high-quality energy resource for China's coastal provinces. With our cost and performance inputs, the model chooses to rapidly build significant amounts of offshore wind. To ensure that they are not overly reliant on a technology that has yet to be deployed on a very large scale in China, we constrain offshore wind deployment in the Current Policy and Clean Energy scenarios by limiting the amount of new offshore wind generating capacity that can be added in different periods. As a sensitivity, we ran capacity expansion and production simulation cases without limits on the deployment of offshore wind.

11 Although these two sensitivities would ideally be undertaken together, we conduct them separately to capture correlation among load, wind, and solar forecast error, due to data limitations.

4
RESULTS

The results are organized into two categories. The first (Section 4.1) includes generation mix, generation capacity mix, generation capacity additions, transmission capacity, and coal plant operations. The second (Section 4.2) includes wholesale cost, total investment, emission reductions, reliability, health impacts, and employment. Results for the sensitivity analyses are integrated into these sections.

4.1 GENERATION AND TRANSMISSION

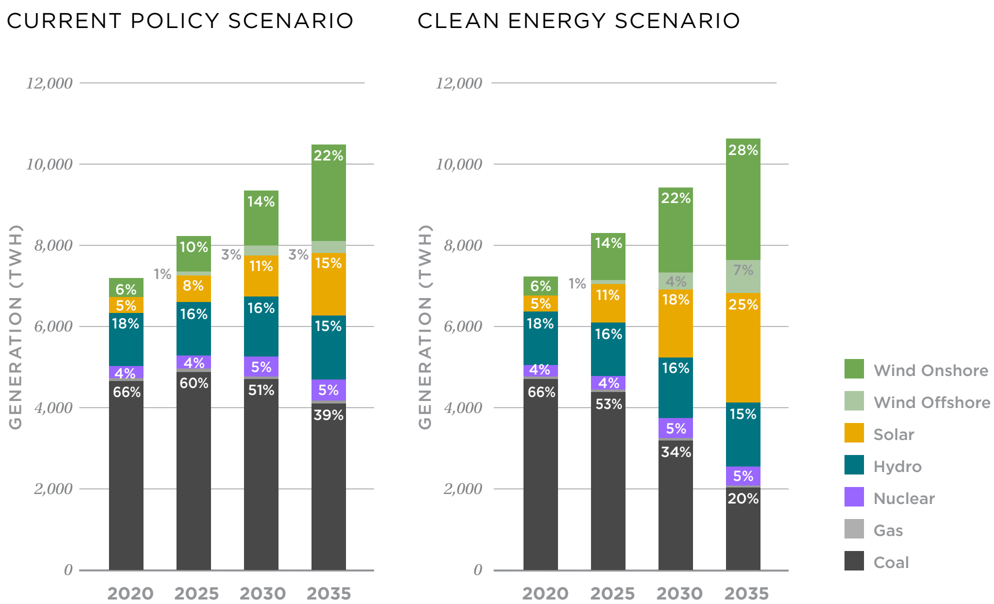
Generation Mix. In the Current Policy scenario, non-fossil generation increases from 34% of total generation in 2020[12] to 60% in 2035, accounting for all new generation and reducing coal generation by about 12% relative to 2020 levels (Figure 5). The Current Policy is consistent with the National Energy Administration's (NEA's) *Energy Production and Consumption Revolution Strategy*, which calls for non-fossil generation to reach 50% of total generation nationwide by 2030.[13] In the Clean Energy scenario, non-fossil generation reaches 80% in 2035, reducing coal generation by 56% relative to 2020 levels.[14] The incremental increase in non-fossil energy in the Clean Energy scenario, relative to the Current Policy scenario, is supplied by expanding onshore wind (47% of increased non-fossil generation), offshore wind (12%), and solar PV (42%) generation (Figure 5).

12 2020 results are modeled rather than actual, but are loosely calibrated to 2020 actuals.

13 NEA (2016).

14 Neither the Current Policy nor the Clean Energy scenario is least-cost, given the inputs and assumptions in this study. Running PLEXOS without limits on annual solar and wind additions and without targets for non-fossil generation results in a least-cost non-fossil fuel generation share of around 70% in 2035. The Clean Energy scenario provides additional emission reductions, relative to least-cost capacity expansion, while reducing average wholesale costs relative to the Current Policy scenario.

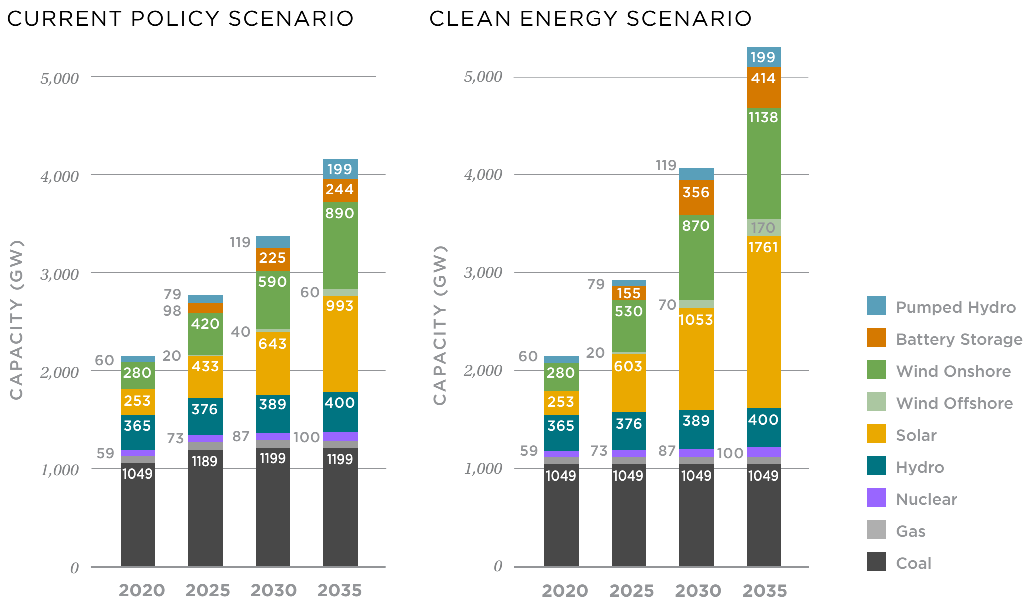
FIGURE 5. *Generation Energy Mix*



Generation Capacity Mix. In the Current Policy scenario, all new generation capacity additions are non-fossil resources, aside from the 150 GW of coal generation under construction (Figure 4). The model is able to build additional coal generation in the Current Policy scenario but chooses not to. This suggests that, with the inputs and assumptions used in this study, a combination of wind, solar, and electricity storage is lower cost than coal for meeting growth in electricity demand. This outcome is consistent with current government policy. Wind and solar generation capacity reach 1,273 GW in 2030 in the Current Policy scenario, in line with the government's 1,200 GW target for 2030,[15] and increases to 1,933 GW in 2035. Declining costs lead to rapid increases in battery storage capacity in the Current Policy scenario, with a total of 98 GW by 2025, 225 GW by 2030, and 244 GW by 2035.

15 NEA (2021a).

FIGURE 6. *Generation Capacity Mix*



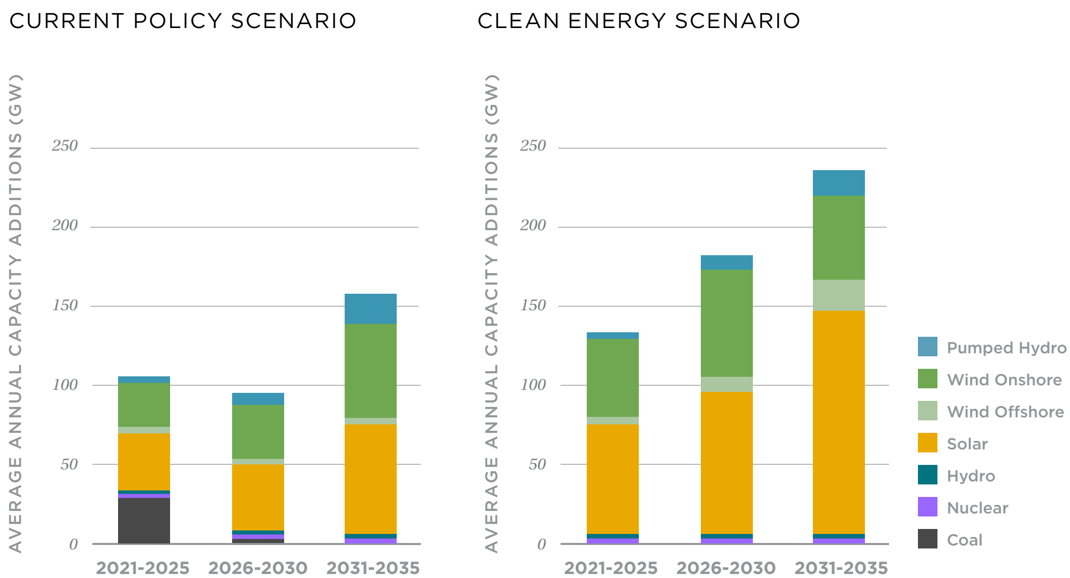
In the Clean Energy scenario, wind and solar generation and battery storage capacity increase more rapidly than in the Current Policy scenario (Figure 6). Divergence between the two scenarios begins in 2020-2025. In the Clean Energy scenario, wind and solar generation and battery storage capacity reach 1,153 GW and 155 GW by 2025, relative to 873 GW and 98 GW in the Current Policy scenario. Wind and solar generation capacity grow further to 1,993 GW by 2030 and 3,069 GW by 2035 in the Clean Energy scenario, significantly higher than current policy targets. Battery storage grows to 356 GW and 414 GW in 2030 and 2035, respectively.[16]

Generation Capacity Additions. In the Current Policy scenario, limits on annual wind and solar generation capacity additions are binding and the model limits annual additions of both resources to 68 GW, 80 GW, and 134 GW per year in 2021-2025, 2026-2030, and 2031-2035 (Figure 7). These rates are conservative; China added 120 GW of wind and solar in 2020.[17] In the Clean Energy scenario, where annual wind and solar additions are driven by economics, wind and solar generation reach an average of 124, 168, and 215 GW per year in the three model periods. Rates of battery additions in both the Current Policy and Clean Energy scenarios are an order of magnitude larger than historical rates.

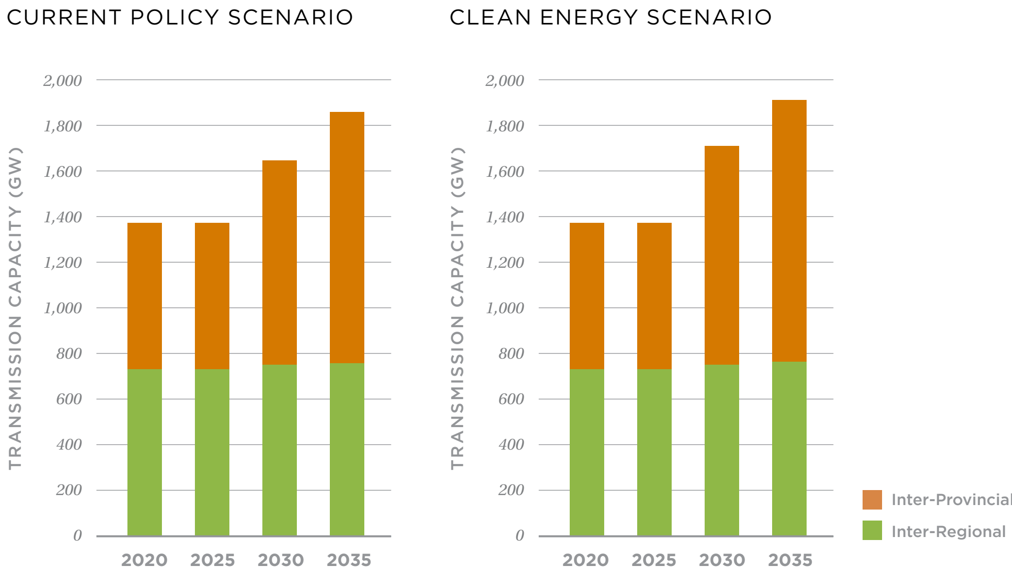
16 Battery facilities are assumed to be replaced after 10 years (~3,000 cycles); the replacement cost is included in our cost estimation.

17 CEC (2021b).

FIGURE 7. *Annual Capacity Additions for Wind, Solar, and Battery Storage*



Transmission Capacity. In the Current Policy and Clean Energy scenarios, the model does not build any new interregional capacity or new interprovincial transmission capacity from 2020 to 2025, which suggests that all cost-effective capacity had already been built by 2020. Interprovincial transmission capacity additions and investment from 2025 to 2035 are only marginally (~3%) higher in the Clean Energy scenario (Figure 8). There are three main reasons for this result: (1) given the deep reductions in installed costs for solar PV and onshore wind, the model can cost-effectively build these resources closer to load centers instead of importing from the highest resource quality regions via long distance transmission lines; (2) low-cost grid-scale storage obviates a large part of the new transmission investments needed for grid balancing; and, (3) electricity demand growth between 2020 and 2035 requires a large increase in baseline transmission investment in the Current Policy scenario, which means that the incremental transmission investment needed in the Clean Energy scenario, relative to the Current Policy scenario, is lower.



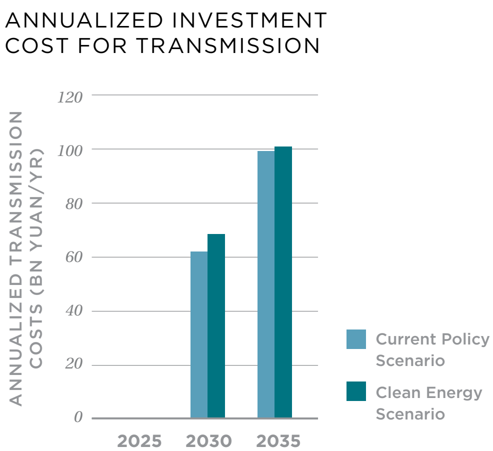
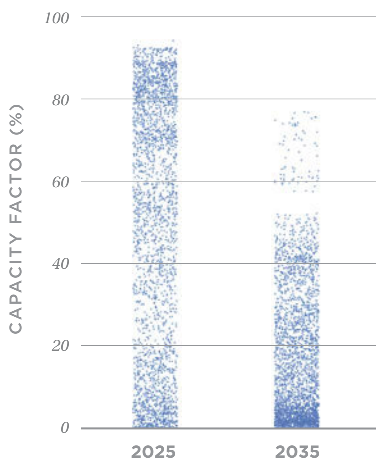


FIGURE 8.
Interprovincial and Interregional Transmission Capacity (Top Panel) and Annualized Costs for New Transmission (Bottom Panel)

Coal Plant Operations. Coal power plant operations change significantly in the Current Policy and Clean Energy scenarios, with steep declines in annual operating hours for most coal generators and increases in the variance of annual operating hours in both scenarios. Average annual operating hours for coal plants fall from 4,526 hours per year (52% annual capacity factor) in 2020 to 3,469 (40%) hours per year in 2035 in the Current Policy scenario and 1,986 (23%) hours per year in 2035 in the Clean Energy scenario. Figure 9 shows the change in annual capacity factors for individual coal units in the Clean Energy scenario, illustrating the high variance in capacity factors among coal units and the overall decline in capacity factors by 2035.

FIGURE 9. *Annual Capacity Factors for Coal Generators*



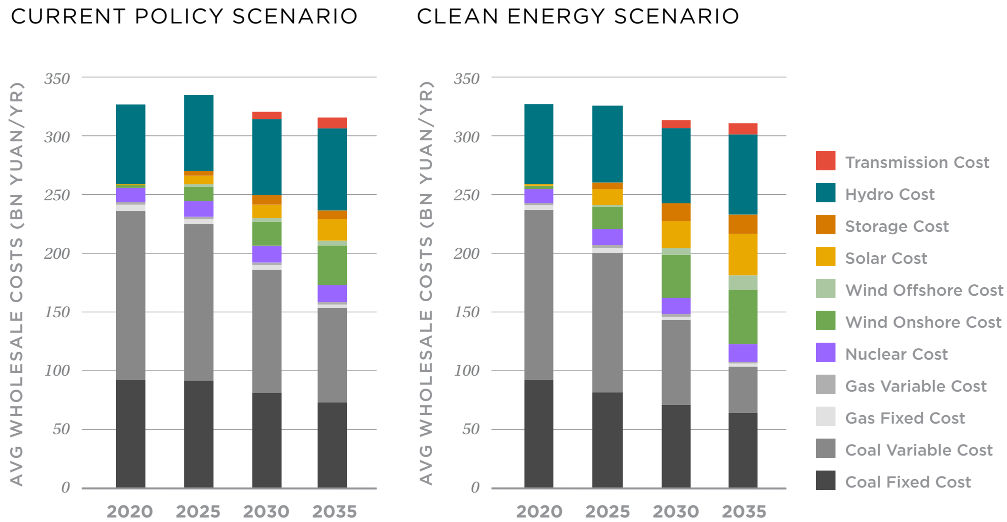
Note: Each dot represents the capacity factor of an individual coal unit.

4.2 COST, RELIABILITY, EMISSIONS, AND EMPLOYMENT

Wholesale Cost. Average wholesale costs[18] are 6% lower in the Clean Energy scenario than in the Current Policy scenario in 2035, because the incremental annualized cost of additional investments in wind, solar, batteries, and transmission in the Clean Energy scenario (497 billion yuan per year) is less than the sum of incremental cost savings from coal and natural gas fuel (426 billion yuan per year) and additional investments in coal generation (95 billion yuan per year) in the Current Policy scenario (Figure 10). Lower average wholesale costs in the Clean Energy scenario suggest that the limits on annual wind and solar generation capacity additions in the Current Policy scenario are below levels that are cost-effective.

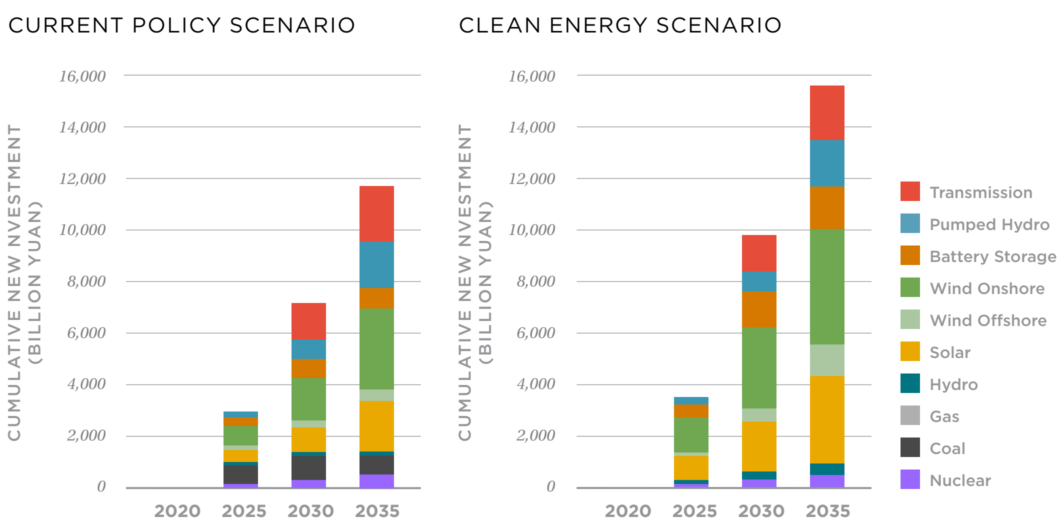
18 Average wholesale costs are total wholesale costs divided by total generation. Here, wholesale costs include installed capacity, fixed O&M, fuel costs for generation, storage, and installed capacity costs for interprovincial and interregional transmission.

FIGURE 10. *Average Wholesale Costs*



Total Investment. Total cumulative investment in the Clean Energy scenario is somewhat higher (516 billion yuan, 17%) than in the Current Policy scenario in 2025, but by 2035 the difference in cumulative investment between the two scenarios grows to nearly 4 trillion yuan (40%) (Figure 11). As discussed above, this large increase in investment is essentially financed using coal fuel cost savings.

FIGURE 11. *Cumulative New Capital Investment for Generation and Transmission*

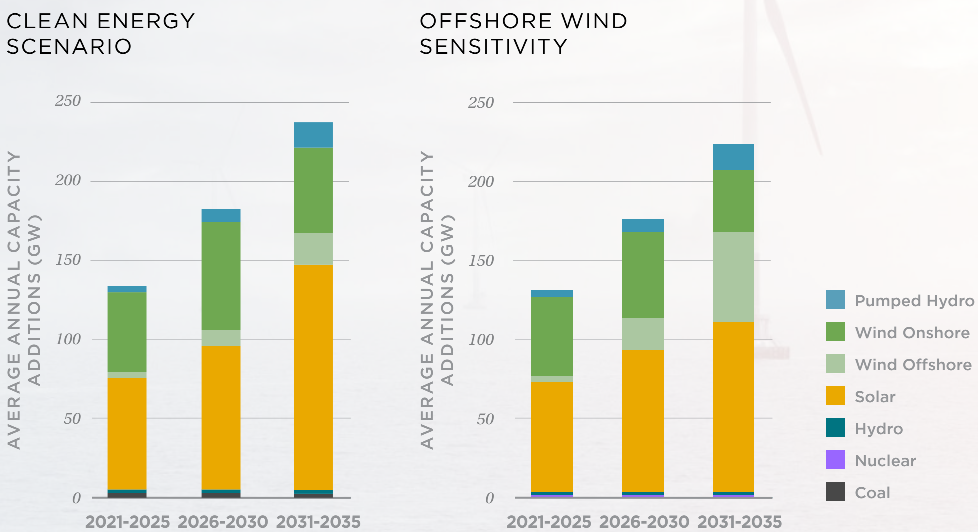


Note: Investment in each year is total cumulative, rather than annualized, investment.

OFFSHORE WIND SENSITIVITY

China has significant, high-quality offshore wind resources along its eastern coast. The offshore wind sensitivity (see Section 3.4 for a description) allows these resources to be rapidly developed. In this sensitivity, we relax limits on annual capacity additions for offshore wind, which allows additional offshore wind to displace onshore wind and solar generation. The share of offshore wind in the generation mix increases from 7% to 15% in 2035, while the shares of onshore wind and solar fall from 28% to 23% and 25% to 23%, respectively. Total offshore wind generation capacity increases from 170 GW to 400 GW, corresponding to annual deployment of 20 GW per year from 2025-2030 and 56 GW per year from 2030-2035 (Figure 12).

FIGURE 12. *Average Annual Capacity Additions under Clean Energy Scenario and Offshore Wind Sensitivity*



In 2035, wholesale costs in the offshore wind sensitivity (322 yuan/MWh) are similar to those in the Clean Energy scenario base case (318 yuan/MWh), and lower than in the Current Policy scenario (327 yuan/MWh). Total generation and transmission investment in the offshore wind sensitivity is comparable to the Clean Energy scenario base case. The results suggest that offshore wind could be an important resource for China's energy system by reducing the need to develop higher-cost (lower resource quality) onshore wind and solar generation resources to meet energy and environmental policy goals.

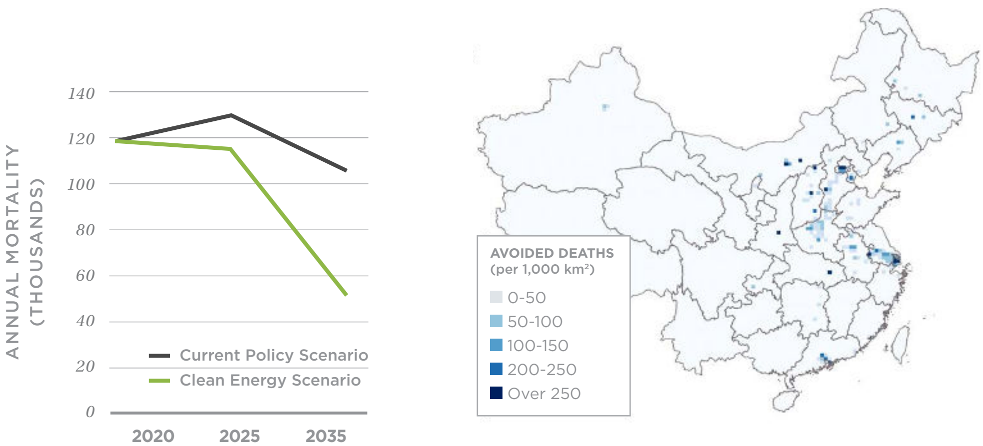
Note: Offshore wind costs include grid interconnection and other incremental transmission costs.

Emission Reductions and Health Benefits. In the Current Policy scenario, CO_2, SO_2, and NO_X emissions intensity (emissions per kWh generated) falls significantly, though absolute emissions increase in the short run and fall only by 12% from 2020 levels by 2035 due to electricity demand growth (Figure 13). In the Clean Energy scenario, CO_2 emissions intensity falls by 70% from 2020 levels, to 0.16 tCO_2/MWh, and absolute emissions fall by 50% (by 1,660 $MtCO_2$) by 2035 (Figure 13). SO_2 and NO_X emission intensities are also much lower in the Clean Energy Scenario.

FIGURE 13.
CO_2, SO_2, and NO_X Emissions Intensities

Lower emissions from coal-fired generation lead to a significant reduction in mortality, with annual deaths related to electricity generation falling by approximately 50% in the Clean Energy scenario, relative to the Current Policy scenario, in 2035. As Figure 14 illustrates, reductions in the intensity of mortality (deaths per 1,000 km^2) are evenly distributed across China.

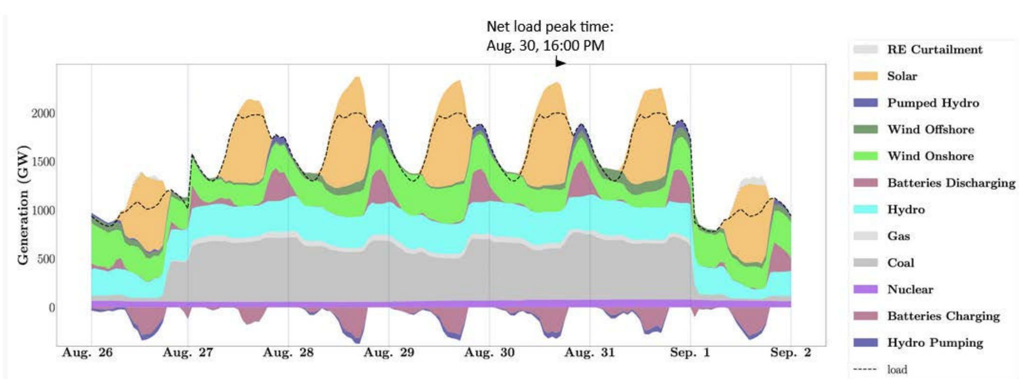
FIGURE 14. *Annual Mortality in the Clean Energy and Current Policy Scenarios, and Map of Avoided Mortality in the Clean Energy Scenario*



Note: The map above shows annual avoided premature deaths associated with power plant emissions under the Clean Energy scenario, compared to the Current Policy scenario

Reliability / Coal Retirements. In the coal retirement sensitivity, 30-year lifetimes reduce the coal capacity to about 800 GW by 2035 — a reduction of about 250 to 300 GW. We find that the electricity system is able to meet demand plus a 10% operating reserve margin during the highest summer and winter net load weeks[19] even with lower coal generation capacity, as reservoir hydropower, gas generation, and storage energy make up the capacity shortfall from retired coal generation (Figure 15).

FIGURE 15. *National System Dispatch in the Highest Net Load Week in Summer 2035, With Coal Retirements*

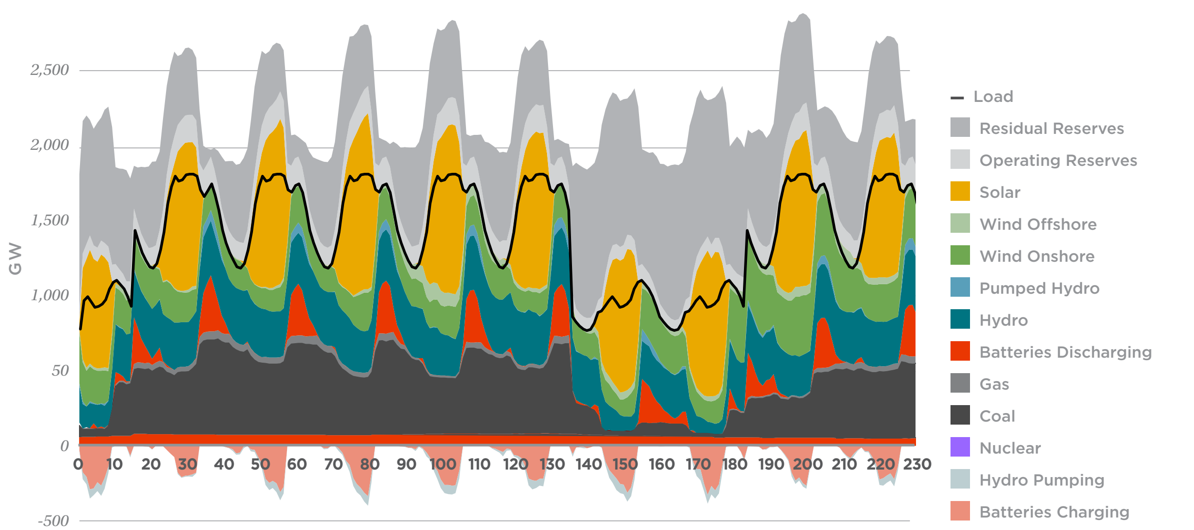


19 The highest net load week is the week with the highest net load peak, where net load is load minus solar and wind generation.

Reliability / Supply and Demand Shocks. During the highest net load hour of the 35-year wind and solar data, wind and solar generation fall by 162 GW relative to our base weather year (2018) wind and solar generation profiles. During the highest net load week in summer, aggregate national renewable energy generation drops by 12% relative to our base year (Figure 16); during the highest net load week in winter, it drops by 14% relative to our base weather year (Figure 17). Because of the regional diversity and resource diversity, the reduction in national aggregate renewable generation availability across the 35 weather years is limited to 12% to 14% during peak load periods.[20]

Other sources of capacity and energy must replace this shortfall. In the dispatch simulation, wind and solar generation are replaced by coal and gas generation. With a 10% demand shock (increase), peak demand increases to nearly 2,000 GW, but the system still has adequate resources to meet demand in the highest summer and winter net load weeks (Figures 18 and 19).

FIGURE 16. *National System Dispatch in the Highest Net Load Week in Summer 2035, Using 35 Years of Weather Data*



20 Within a province or at an individual site level, the inter-annual variation in renewable generation would be higher than the national aggregate number.

FIGURE 17. *National System Dispatch in the Highest Net Load Week in Winter 2035, Using 35 Years of Weather Data*

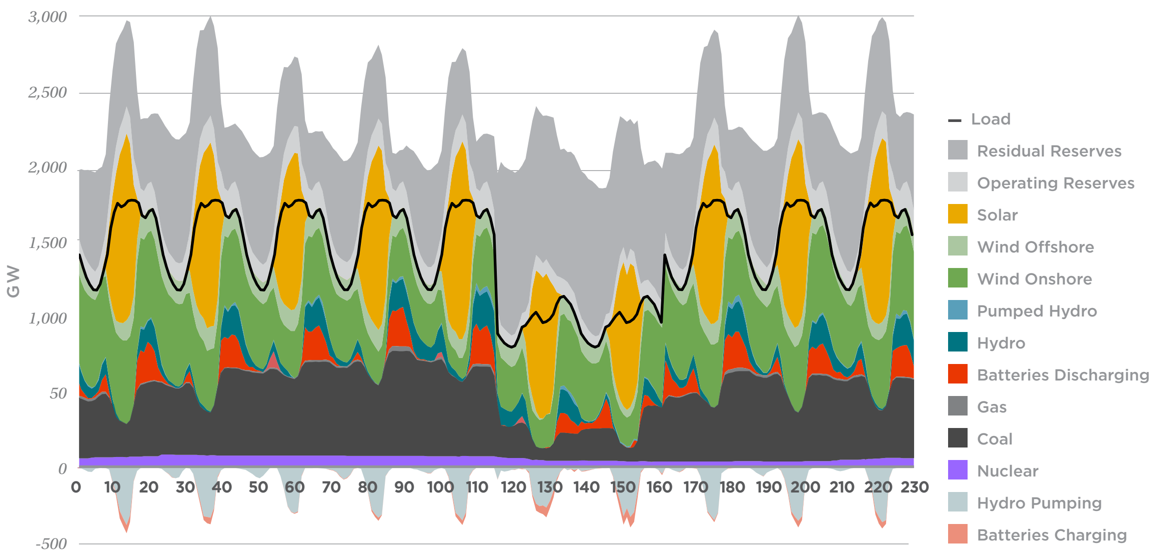


FIGURE 18. *National System Dispatch in the Highest Net Load Week in Summer 2035, with a 10% Demand Shock*

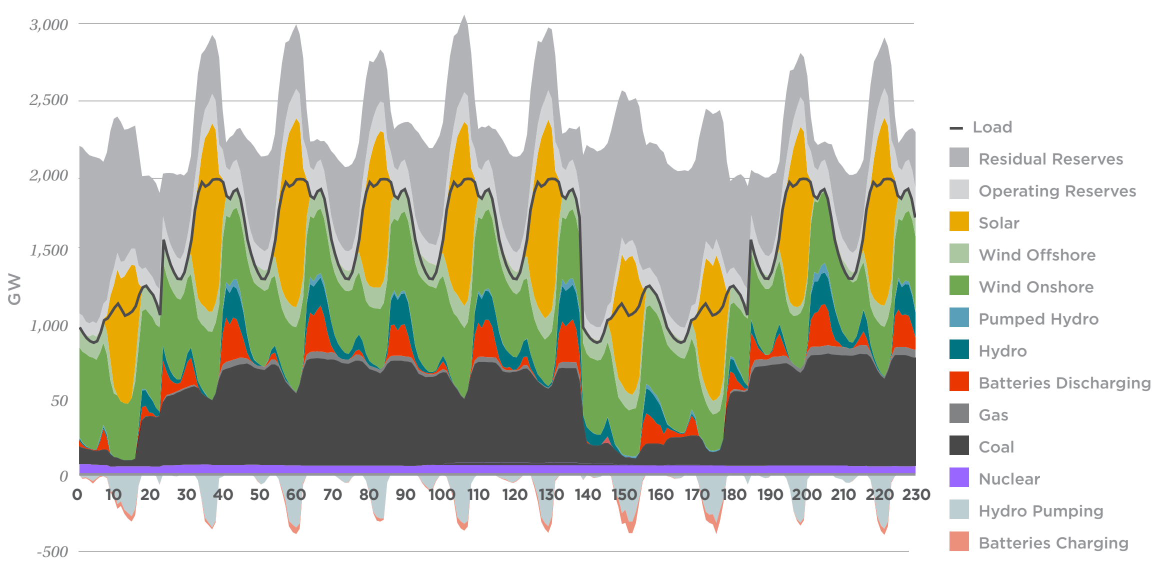
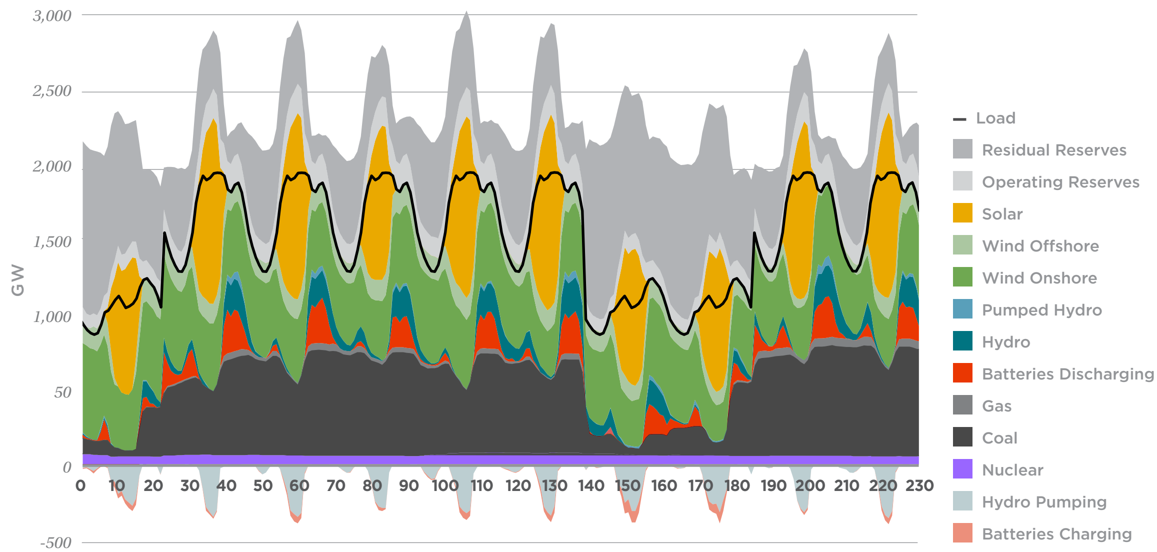


FIGURE 19. *National System Dispatch in the Highest Net Load Week in Winter 2035, with a 10% Demand Shock*

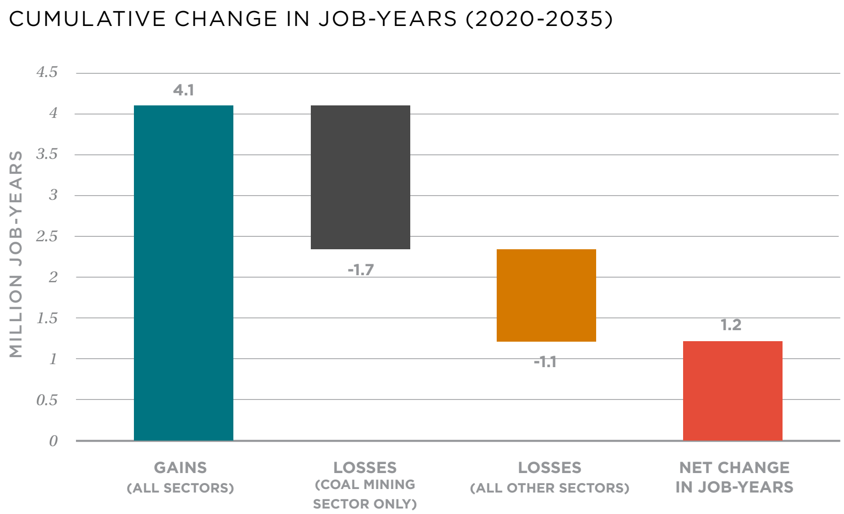


Employment. Increases in non-fossil generation in the Clean Energy scenario lead to significant shifts in expenditures within the electricity sector, in particular from spending on coal fuel to construction and manufacturing spending on wind, solar, and energy storage installations. This shift in expenditures leads to changes in employment, with lower spending on coal fuel leading to reduced employment concentrated in the coal mining sector, and higher spending on construction and manufacturing leading to higher net employment.

We estimate that the lower spending on coal generation leads to a total of 1.7 million cumulative coal mining job-years lost from 2020 to 2035. Other (non-coal) sectors experience a loss of 1.2 million job-years in aggregate over the same period. In contrast, higher spending on wind, solar, and energy storage leads to a total gain of 4.8 million cumulative job-years from 2020 to 2035, for a net increase of 1.9 million job-years (Figure 20). These results are highly sensitive to assumptions about the labor productivity growth rate in each sector, particularly in the coal mining sector. Removing productivity growth rates from the calculation results in a net gain of 4.3 million job-years by 2035.

The net employment effects of the shift from fossil to non-fossil generation are relatively small, both in absolute terms and relative to the size of China's labor force. However, because changes in employment will be uneven both across provinces and across time, managing the macroeconomic impacts of the transition from fossil to non-fossil generation will likely require careful policy support.

FIGURE 20. *Cumulative Net Employment Effects of Clean Energy Scenario*



5
CONCLUSIONS, RECOMMENDATIONS, AND FUTURE RESEARCH

Sustained declines in costs for wind, solar, and electricity storage technologies create new opportunities to lower wholesale costs and reduce emissions in China's electricity sector. The results of this study suggest that expanding the share of non-fossil electricity generation from around 60%, under current policies (Current Policy scenario), to 80% (Clean Energy scenario) by 2035 would lower wholesale electricity costs and support the Chinese government's goals for carbon neutrality and air quality. Transitioning to an electricity system with 80% non-fossil generation would require overcoming barriers to the development and integration of wind generation, solar generation, and energy storage.

This final section summarizes the study's key conclusions, provides recommendations for changes in policy and regulation based on the results, and outlines priorities for future research identified through this study.

5.1 KEY CONCLUSIONS

The analysis in this study supports five key conclusions.

Declining wind, solar, and electricity storage costs are changing the economics of China's electricity sector.

The Current Policy and Clean Energy scenarios illustrate emerging changes in the economics of China's electricity sector. In both scenarios, the lowest cost resources for meeting growth in electricity demand are a combination of wind, solar, and battery storage. This result suggests that a combination of these resources is lower cost than building new coal generation.

In the Clean Energy scenario, adding additional wind, solar, and energy storage cost-effectively reduces generation from existing coal plants because the incremental cost of additional wind, solar, storage, and transmission is lower than the fuel cost savings from reduced coal plant operations. This result suggests that, in the Clean Energy scenario, it is lower cost to build new wind generation, solar generation, and some battery storage than to continue to operate existing coal plants.

China's electricity system can be reliably operated with high levels of non-fossil generation.

The reliability sensitivity showed that China's electricity system could maintain high standards of reliability with an 80% non-fossil generation mix that includes 60% wind and solar generation in 2035. With higher levels of wind, solar, hydropower, and electricity storage, reliability concerns will shift from capacity adequacy to capacity and energy adequacy. However, even during prolonged periods of low wind and solar generation and unanticipated load increases, China's electricity system would be able to maintain adequate capacity and energy. New coal generation is not needed to ensure resource adequacy.

The two key enabling conditions for ensuring reliability with high levels of renewable generation are (1) a robust approach for optimizing the operation of electricity storage facilities, to ensure that individual storage operations support the reliability of the electricity system as a whole; and, (2) regionally and nationally coordinated operations, to ensure that provinces and regions that are short power can seamlessly import from neighboring provinces and regions on shorter and longer timescales.

Exceeding existing goals for non-fossil generation would deliver additional emission reduction and health and employment benefits.

Increasing the share of non-fossil generation to 80% would support significant additional reductions in CO_2 emissions and health costs and mortality related to poor air quality. Emission reductions and health benefits would be greater than the estimates in this study (Section 4.2) due to electrification. For instance, transportation electrification, combined with an accelerated shift to non-fossil generation, will reduce both vehicle tailpipe and power plant emissions. The combination of electrification and accelerated deployment of non-fossil generation would thus be a powerful tool to hasten progress toward China's environmental goals.

Reductions in coal generation would lead to continued reductions in employment in the coal mining industry, but these losses would be offset by increases in employment driven by investment in wind, solar, hydropower, nuclear, and batteries. Lower wholesale electricity costs, if translated into the prices that retail customers pay, would also drive increases in employment. The challenge for policymakers in China will be to manage the transition in employment and tax revenues from an electricity sector dependent on coal to one dependent on non-fossil resources, without undermining the economics of new non-fossil generation.

Reaching cost-effective levels of non-fossil generation will require overcoming barriers to wind, solar, and storage development and integration.

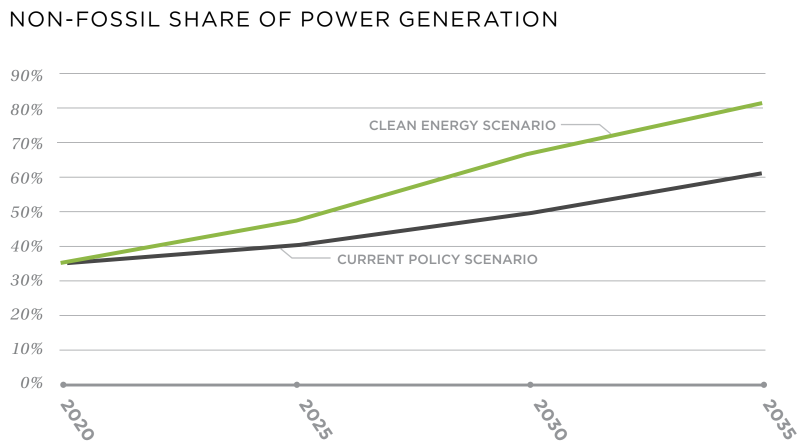
The Clean Energy scenario involves the development of wind, solar, and storage on an unprecedented scale. Wind and solar generation reach a combined 1,153 GW in 2025, close to the current 2030 target (1,200 GW), and grow further to nearly 2,000 GW in 2030 and just over 3,000 GW in 2035. Battery storage grows from MW scale in 2020 to 100-GW scale by 2025.

For wind, solar, and electricity storage to be developed and integrated into the electricity system on this scale, barriers to scaling will need to be overcome. The scenarios in this study provide a useful analogy for what overcoming barriers entails. In the Current Policy scenario, annual solar and wind generation capacity additions (GW/yr) are constrained to historical levels. As in the Clean Energy scenario, where these constraints are relaxed, overcoming barriers to scaling will mean finding ways to enable more rapid development and integration of wind, solar, and storage than has occurred historically. The most important barriers are around regulation and markets, electricity system operations, and land use. Section 5.2 discusses these barriers in greater detail.

The shift to a low-cost renewables pathway begins in the next five years.

The share of non-fossil generation in the Current Policy and Clean Energy scenarios begins to diverge in the 2020-2025 time period (Figure 21), suggesting that policy and regulatory changes to accelerate non-fossil deployment should begin in the 14th five-year planning period (2021-2025), rather than waiting until the 15th Five-Year Plan (2026-2030). In particular, while there already may be momentum behind accelerated expansion of wind and solar generation, a near-term priority would be to lower barriers to the rapid expansion of battery storage.

FIGURE 21. *Non-Fossil Share of Generation, Current Policy and Clean Energy Scenarios*



5.2 POLICY RECOMMENDATIONS

Priority areas for reducing barriers to rapid wind, solar, and storage deployment include policy targets, markets and regulation, and land availability and use. Changes in these three areas would facilitate the shift from renewable energy as a peripheral resource to the backbone resource in China's electricity system.

5.2.1 Policy Targets

Targets for generation capacity and the share of non-fossil generation have historically played an important role in providing China's electricity industry with guidance on the direction of national policy. There is no indication that policy targets will not continue to play this role in the future.

Increase 2030 targets for non-fossil generation and renewable generation capacity, and consider adding storage targets

The results of this study suggest that increasing the 2030 target for non-fossil generation from 50% to as much as 65% and the 2030 target for wind and solar generation capacity from 1,200 GW to around 2,000 GW could lead to significant additional CO_2 emission reductions and health benefits at low or even negative cost, while positioning China to mostly decarbonize its electricity sector throughout the 2030s and enhance energy security.

In 2021, the NEA increased its target for pumped hydropower to 120 GW by 2030.[21] China's *Action Plan for Carbon Dioxide Peaking Before 2030* set a target of 30 GW or more for new types of energy storage by 2025.[22] Developing explicit, longer-term targets for electricity storage could provide helpful signals to storage manufacturers and the electricity industry on the expected pace and scale of electricity storage capacity and integration needs.

Set targets for the share of non-fossil generation capacity for 2035

China does not yet have non-fossil generation and wind, solar, hydro, and nuclear generation capacity targets for 2035. Adoption of 2035 targets could also provide helpful signals to manufacturers, the electricity industry, and provincial and local governments on the expected pace and scale of change.

5.2.2 Markets and Regulation

Changes in regulation that mainstream and create stable business models for wind, solar, and storage in electricity resource procurement and markets will be important to reduce barriers to more rapid deployment of these resources. Mainstreaming involves progress through a series of interrelated reforms that are already underway.

Consolidate approaches to renewable energy procurement and focus on participation in forward contract markets

The first of these reforms is in resource procurement. Currently, renewable generation in China is bought and paid for through a combination of several feed-in tariff and market-based procurement mechanisms, many of which result in excessive losses and unpredictable revenues for renewable generators.[23] In addition, these mechanisms do not enable direct wholesale competition between renewable generation and thermal generation.

21 NEA (2021b).
22 State Council (2021).
23 Yong (2022).

To address this problem, the different approaches to procuring renewable generation can be jettisoned in favor of a single approach — procurement through forward contract markets (中长期交易). Under this approach, renewable generation competes directly with thermal generation for forward contracts with industrial and grid company buyers. This approach is consistent with the intent of electricity market reforms in 2015 and the direction of renewable energy procurement guarantee policies in China.[24]

To level the playing field for different kinds of resources, forward contract markets can be extended (e.g., longer-term contracting, more tailored contracts) to allow for more frequent and flexible trading by buyers and sellers, while continuing to have shorter-term (e.g., monthly) auctions. Recent experience in the U.S. illustrates that renewable generation can directly compete with thermal generation in forward procurement.[25] Spot markets will help to support participation by renewable generation in forward markets, by reducing the perceived need for physical delivery of contracted generation.

Continue progress in developing electricity spot markets and support their evolution into regional markets

For renewable generation to participate in forward markets on a larger scale, it will be important to resolve issues around imbalance costs. Imbalance costs include the difference in energy between what a seller generates and a buyer consumes, differences in locational costs due to congestion, and the costs imposed on the electricity system due to wind and solar forecast error. Real-time energy spot markets provide a natural mechanism for addressing these costs, allowing sellers and buyers to pay spot market prices to settle imbalances and to determine in their contracts which party will take on the risk for imbalance costs. U.S. experience has been that which entity is best positioned to manage this risk will depend on buyer and seller size, balance sheets, and sophistication.

China has several provincial spot market pilots underway. Most of these pilots feature some form of nodal pricing, 15-minute dispatch and settlement, and some pilot provinces have allowed participation by renewable generation. These spot markets continue to be in trial operation mode, however, and will need continued development of market designs and regulation to support their more formal implementation. Formal implementation of these spot markets will be an important complement to forward markets. As spot markets in China mature, shifting to

24 The NEA's 2015 *Measures on Advancing Electricity Market Development* (关于推进电力市场建设的实施意见) encouraged renewable generation to participate in emerging electricity markets (NEA, 2015). Its 2016 *Measures for Guaranteed Full Procurement of Renewable Generation* (可再生能源发电全额保障收购办法) envisioned that minimum support guarantees for renewable generation would eventually give way to forward and spot market participation (NEA, 2016b).

25 Kahrl (2021a).

5-minute dispatch and settlement will help to level the playing field for wind and solar generation by reducing imbalance charges related to forecast error.

Several areas of work are needed to complement spot energy market development. They include: 1) developing system operator-run ancillary services (AS) markets that procure frequency regulation reserves and operating reserves through competitive mechanisms, paid for by loads rather than generators; 2) continuing to shift forward contracts to contracts for differences (CfDs) to enable greater real-time operational flexibility; and, 3) developing new financial products that allow market participants to hedge longer-term risk.

Lastly, spot market development will need mechanisms that facilitate greater coordination in markets and operations between provinces and regions, ideally through a single regional market operated by a regional system operator. The NDRC and NEA's 2021 *Rules for Interprovincial Spot Market Transactions* (省间电力现货交易规则) provide a framework for coordinating among interprovincial spot markets, in which provincial markets incorporate export supply and import demand curves from other provincial markets, inclusive of transmission charges.[26] However, U.S. experience has been that a single regional system operator can better manage reliability, support more efficient dispatch and avoid inefficient dispatch due to high transmission charges, and coordinate regional resource adequacy and transmission investment relative to multiple coordinated spot markets or bilateral coordination among utilities.[27]

Strengthen the renewable quota and green certificate system

Even if new wind and solar generation are low cost, these cost advantages may not be reflected in forward or spot markets in the nearer term, where markets need more time to develop and buyers and sellers lack experience with market mechanisms. For instance, imbalance charges for renewable generators may be excessively high as day-ahead and real-time energy markets take shape. China also has more than 500 GW of existing wind and solar generation that may have higher costs and would need some form of out-of-market support mechanism in the transition to a more market-oriented approach for procurement of renewable generation.

In the near term, strengthening the existing renewable quota and green certificate system could help to provide support for existing renewable generators and continue to drive the market for renewable energy. The most important areas to strengthen are: to tie the quotas more closely to policy targets, clarify responsibility

26 NDRC and NEA (2021).
27 For estimates of the benefits provided by regional system operators, see PJM (2019) and MISO (2021).

for meeting the quotas, and enforce the quotas.[28] If renewable generators are participating in forward markets, it will be most effective and efficient if the quota system is implemented on market buyers (industrial customers and grid companies), with penalties for non-compliance that exceed the premiums in renewable certificates.

Develop market participation models for electricity storage

This study projects that battery storage will be cost-effective on a hundred-GW scale by 2025, but to our knowledge China does not yet have stable mechanisms to procure or operate battery storage. Thus, there is a gap between the large-scale potential for electricity storage in China's electricity system and the mechanisms that would allow it to be developed and integrated on this scale.

Electricity storage can provide an array of services: firm capacity, energy arbitrage, congestion management, regulation and operating reserves, and distribution and transmission cost savings. Storage, and particularly battery storage, can be located almost anywhere in the electricity system — at a generation facility, behind the customer meter, on the high voltage transmission system, on the sub-transmission system, or on the distribution system. Models like the one used in this study often only capture part of the value provided by storage and provide limited insight on where storage should be optimally located, for instance at a solar facility, directly connected to the transmission system, or at an industrial facility. Market pricing can help to better value storage and determine where it should be optimally sited.

Allowing electricity storage to participate in forward and spot markets can help create stable business models for electricity storage, giving buyers and sellers the flexibility to determine how storage is best used based on services provided, where it is best sited, and who should own it. This would enable multiple revenue and ownership models for storage. U.S. electricity markets can provide a useful reference on rules for energy storage participation in spot markets.

Integrate distributed energy resources into wholesale markets

Distributed energy resources (DERs), including distributed generation, distributed electricity storage, and demand response (DR), can provide an important source of energy and flexibility to complement bulk system resources. DR has long been a focus area for policy in China, and recent policies have sought to encourage distributed generation and storage. To maximize the larger value of DERs, the operation of these resources will need to be integrated into wholesale markets. There are multiple potential strategies for doing so, including tariffs that reflect market prices or direct participation of DERs in wholesale markets. DER integration into wholesale markets is an ongoing area of innovation and market reform in the U.S.[29]

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28 Yong (2022).
29 ESIG (2022).

Develop resource adequacy processes and mechanisms

Ensuring long-term resource adequacy in China's electricity system, as it undergoes transitions to markets and to new resources, will likely require more systematic and formal resource adequacy processes. Such processes would identify levels of firm capacity needed to meet a reliability target, include mechanisms that encourage adequate levels of investment in firm capacity, facilitate an efficient and fair allocation of the costs of those investments, and incentivize the real-time availability and performance of resources that are counted toward firm capacity. U.S. electricity markets have multiple approaches to resource adequacy that can be a useful reference for China.[30]

The importance of resource adequacy mechanisms increases with rising levels of renewable generation and storage. High levels of wind and solar generation will tend to depress energy market prices, which implies that generation and electricity storage needed for reliability will need to increasingly rely on scarcity pricing to recover their fixed costs. Research in the U.S. suggests that a variety of existing approaches can ensure resource adequacy and revenue sufficiency for generators under higher renewable penetrations, though they will require continued enhancements, including: better accounting for the firm capacity value of renewable generation and storage; improved scarcity pricing and market price formation; improved generator and storage availability and performance; and, more responsive demand.[31]

5.2.3 Land Use

Terawatt-scale development of wind and solar generation will require a significant amount of land, on the order of millions to tens of millions of hectares.[32] Ensuring that adequate land is available at an economic cost, and that wind and solar development do not conflict with national and local land conservation priorities, requires greater attention to the land use implications of wind and solar development.

Prioritize land use efficiency

Technological improvements have significantly reduced the land footprint of onshore wind and utility-scale solar PV over the past decade through increased

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30 For an overview of U.S. experience with RA mechanisms, see Kahrl et al. (2021b).

31 Levin and Botterud (2015); Frew et al. (2016); Wolak (2020); Ela et al. (2021).

32 At the approximately 3 TW of wind and solar in the Clean Energy scenario, the range here would implicit assume a power density of between 0.3 and 3 MW/ha.

power (MW/ha) and energy (MWh/ha) densities.[33] In the U.S., improvements in both technologies were driven by incentives to increase energy generation (MWh) and capacity factors (annual operating hours). In China, as wind and solar become a more important part of the electricity system, government policy should also shift from an emphasis on installed capacity to an emphasis on energy generation from these resources, which will also help to encourage innovation that supports efficient land use. The renewable quota system is a step in this direction.

Offshore wind and distributed solar PV can also help to reduce the land use impacts of terawatt-scale wind and solar development. Electricity market designs, policies and tariffs for distributed generation, land prices, and transmission availability will all play important roles in determining the balance among onshore versus offshore wind, utility-scale and distributed solar, and local generation versus imports in China's coastal provinces. This suggests the need for coordination among land use priorities, electricity resource planning, and transmission planning.

Integrate wind and solar development into land use and conservation planning

Renewable developers will need clear guidance from government agencies to direct them toward project sites that do not conflict with conservation and agricultural land use priorities. Integrated land use planning can be an important source of transparent, rigorous guidance. In the U.S., tools for integrated land use planning have improved significantly over the past decade and could provide a helpful reference for China.[34]

5.3 PRIORITY AREAS FOR RESEARCH

Through this study, we identified several priority areas for research. The overviews below describe key research questions for each area.

Electricity demand forecasting. How can long-term electricity forecasts used in infrastructure planning and policy modeling account for the impacts of electrification and demand flexibility on load shapes? How can uncertainty in electricity demand be best captured in planning and policy studies?

Resource adequacy planning. Which entities should be responsible for long-term planning to ensure that there are adequate resources in the electricity system to meet reliability targets? How should wind, solar, and storage be credited toward

33 For an analysis of how technological innovations in solar PV have reduced its land requirements, see Bolinger and Bolinger (2021). Large increases in rotor diameter and hub height over the past two decades (DOE, 2021) have reduced the land requirements for onshore wind power.

34 For an overview, see https://www.nature.org/en-us/about-us/where-we-work/united-states/california/stories-in-california/clean-energy/.

resource adequacy? How should resource adequacy mechanisms be designed and enforced? Should resource adequacy be regional or national? How should resource adequacy mechanisms be integrated with spot markets?

Electricity storage policy strategy. What are the ownership, business, and operational models that will be most appropriate to China's electricity system? What mix of policies and markets can help to rapidly increase the scale of electricity storage?

Offshore wind policy strategy. What technologies, ownership and business models, and approaches to transmission interconnection are most appropriate to China's offshore wind industry? What mix of policies and markets can help to rapidly increase the scale of offshore wind manufacturing and deployment?

Transition pathways for regional wholesale electricity markets. How can China's emerging electricity spot markets be consolidated into regional markets? How can China overcome the political challenges to forming regional electricity markets that have frustrated progress toward regional markets in the U.S.?

Emission allowance markets and renewable quota implementation and harmonization. In the nearer term, how can the implementation of China's cap-and-trade system, along with its emissions allowance trading, and China's renewable quota system be strengthened? In the longer term, how can these two systems be harmonized to ensure that they remain effective to support national goals and provide consistent incentives?

Integrated land use planning. How can land use planning ensure efficient and fair access to land for wind and solar developers, while minimizing the impacts of wind and solar development on conservation goals and the agricultural sector?

International collaboration. How can international collaboration best support China's transition to a non-fossil fuel energy system: which topics, what modes of collaboration, and which partners?

System security. How can China's power system address the system security challenges of operating with higher levels of intermittent solar and wind generation, including primary frequency control and voltage stability concerns?

Management of technological uncertainty. How can energy policy, regulation, and markets in China be designed to encourage innovation in new zero emissions technologies and enable the lowest cost, most effective technologies to rapidly achieve scale?

6
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TECHNICAL APPENDICES

APPENDIX A | MODELING APPROACH

The state-of-the-art methodology for studies that assess the impacts of high renewable energy penetration on electric power systems is to use capacity-expansion and production cost models. For this study, we use PLEXOS, an industry standard capacity expansion and production cost model, to assess:

- the least-cost ("optimal") generation mix and inter-provincial transmission investments between 2020 and 2035;
- that meet regional electric power demand requirements, based on grid reliability (reserve) requirements, technology resource constraints, and policy constraints.

The study focuses on model years 2025, 2030, and 2035. For each year, we simulate hourly economic dispatch using the PLEXOS production cost model to ensure that the grid can run reliably for all 8,760 hours in the year, including the hours when the system is most constrained.

PLEXOS uses deterministic or stochastic, mixed-integer optimization to minimize the cost of meeting load given physical (e.g., generator capacities, ramp rates, transmission limits) and economic (e.g., fuel prices, start-up costs, import/export limits) grid parameters. Moreover, PLEXOS simulates unit commitment and actual energy dispatch for each hour (at 1-minute intervals) of a given period. As a transparent model, PLEXOS makes available to the user the entire mathematical problem formulation. The model minimizes total generation cost (fixed plus variable costs) for the entire system, including existing and new generation capacity and transmission networks. We assess the optimal resource mix under a range of scenarios examining deployment rates, coal plant retirements, demand growth, electricity market design, demand response, and supply chain challenges.

We represent the Chinese electricity grid using 32 interconnected nodes: one node for each province (Figure A1). These nodes are connected using 182 inter-provincial transmission interfaces. The transfer capacity of each inter-provincial interface is assumed to be half the sum of transmission line capacities between the two provinces in order to capture the operating constraints in an AC power transmission network.

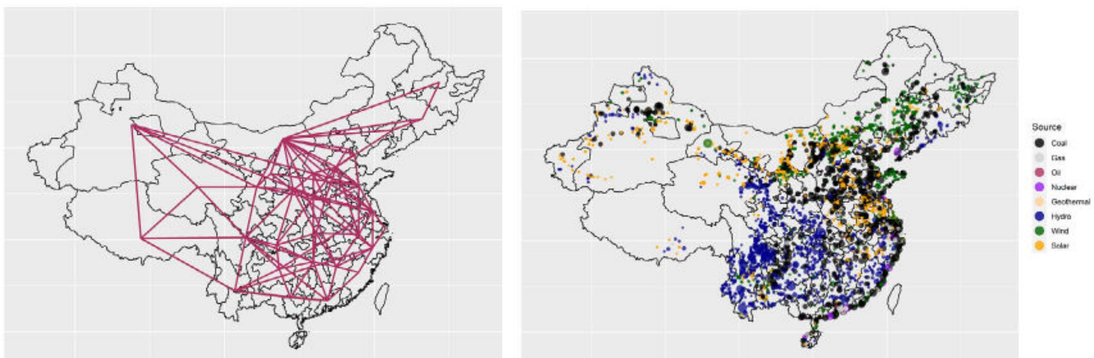


FIGURE A1. *(a) Transmission network represented in the model, (b) individual power plants in 2020 as represented in the model.*

Figure A2 depicts our overall method and the various data components.

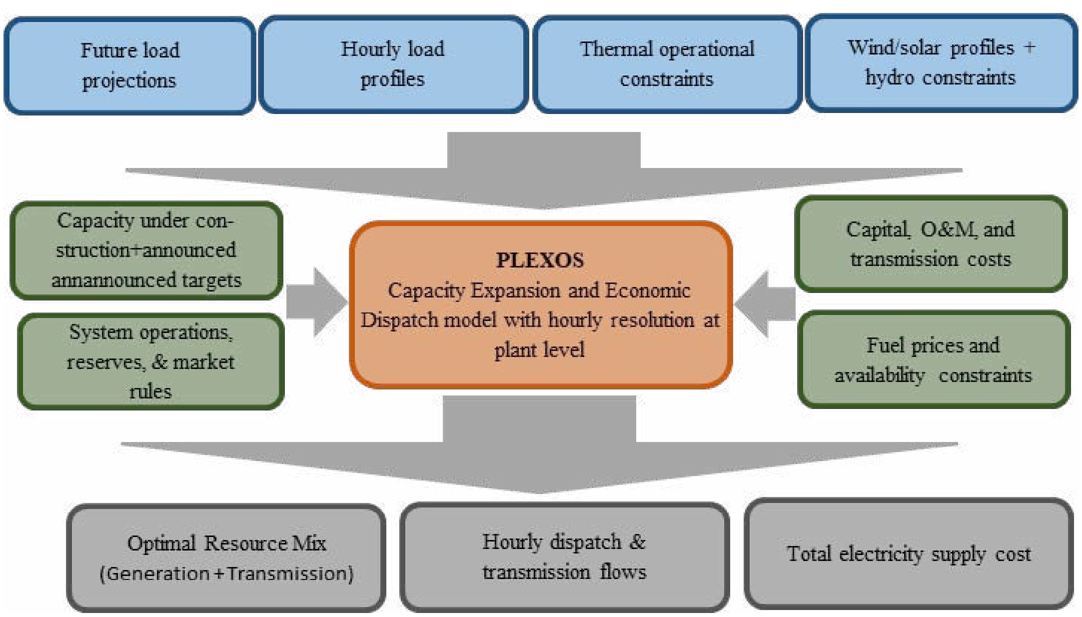


FIGURE A2. *Overall modeling approach*

1.1 OPERATIONAL PARAMETERS

Operational parameters such as ramp rates, technical minimum levels, auxiliary consumption, minimum up and down times, etc. have been taken from the actual data used in previous China and U.S. studies, regulatory norms, and expert / industry consultations. They are summarized in Table A1.

TABLE A1. *Assumptions on Operational Parameters of Power Plants*

	COAL (NEW)	GAS CCGT	GAS CT	HYDRO	NUCLEAR	BATTERY	PUMPED HYDRO
Planned Outage rate	5%	5%	5%	5%	10%	1%	5%
Forced Outage rate	5%	5%	5%	5%	10%	1%	5%
Technical Minimum Level %	40%	30%	20%	0%	90%	0%	0%
Cold-start time (hours)	24	12	1	#N/A	96	0	#N/A
Minimum up-time (hours)	12	6	1	0	96	0	0
Minimum down-time (hours)	6	3	1	0	96	0	0
Cold-start Cost ($/MW)	100	30	1	#N/A	#N/A	#N/A	#N/A
Ramping (% of installed capacity per minute)	1%	2%	10%	100%	#N/A	100%	100%
Auxiliary Consumption	7%	5%	2%	1%	10%	0.5%	1%
Roundtrip Efficiency	#N/A	#N/A	#N/A	#N/A	#N/A	90%	80%

1.2 HEAT RATES

We use actual heat rate data for every power plant using several sources such as Global Energy Monitor, the World Resources Institute's Global Power Plant database, SWITCH-China model industry/expert consultations, and previous literature. We model the heat rate as a function of generator loading, meaning that as the power generation from a unit drops, the heat rate will increase. Figure A3 shows the heat rate function used for a new 660 MW supercritical power plant.

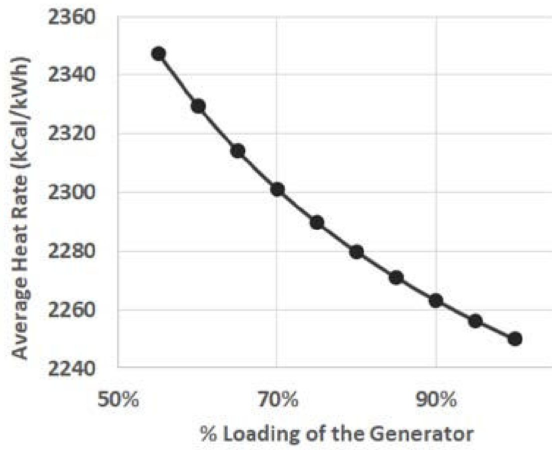


FIGURE A3. *Average heat rate of a coal unit (660 MW supercritical) as a function of unit loading*

At loading level of 50%, the heat rate increases by over 5% of the design heat rate at rated capacity.

APPENDIX B | MODELING INPUTS

Projections of installed costs and fixed operations and maintenance (O&M) costs for onshore wind, offshore wind, solar PV, and battery storage in China are taken from Bloomberg New Energy Finance (BNEF) 2020 forecasts. Table B1 shows the assumptions on capital costs of wind, solar and battery storage.

TABLE B1. *Wind, Solar and Battery Storage Capital Cost Assumptions*

	2025	2030	2035
Onshore Wind (2020 yuan/kW)	5338	5135	4914
Offshore Wind (2020 yuan/kW)	14582	13885	13314
Solar PV (2020 yuan/kW)	2599	2282	2029
Battery storage (4 hour, 2020 yuan/kWh)	406	311	267

CONVENTIONAL POWER PLANT FIXED COSTS

Conventional technology (coal, nuclear, natural gas, and hydro) capital and fixed O&M costs have been taken from multiple sources including Bloomberg, He et al (2021), and industry consultations. Table B2 summarizes the assumptions.

TABLE B2. *Assumptions on Fixed Costs of Conventional Technologies*

TECHNOLOGY	CAPITAL COST OF NEW CAPACITY (2020 YUAN/KW)	FIXED O&M COST (2020 YUAN/KW-YR)
Coal (Ultra supercritical)	3170	95
Gas (CCGT)	1965	114
Hydro	9510	171
Nuclear	13314	628

Note: costs converted to 2020 yuan using exchange rate of 6.34 yuan/USD

ESTIMATING THE TOTAL COST OF GENERATION

New Investments

PLEXOS outputs total capital investment in new generation and transmission assets starting in 2020. We annualize the investment costs by using a real weighted average cost of capital (WACC) of 5% and technology-specific assumptions for economic lifetimes (see Table B3). PLEXOS also outputs the total operations and maintenance (O&M) costs (fixed and variable) and fuel costs of the existing as well as new generation capacity.

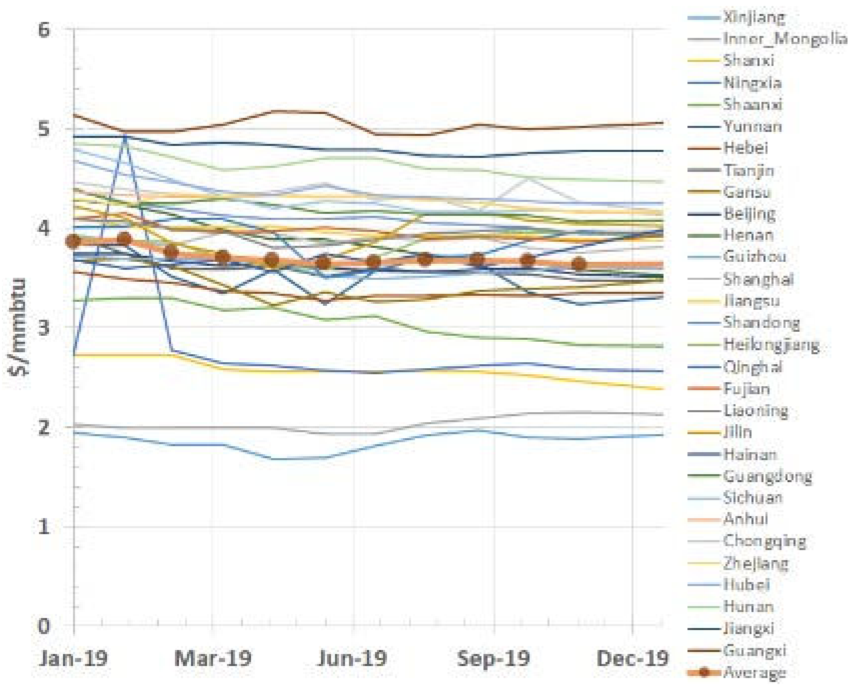
Existing Assets

PLEXOS does not report the investment cost of generation capacity built before 2020, which we estimate exogenously. First, we assess the undepreciated value of generation assets built before 2020, using data from the WRI global power plant database for plant level commissioning dates. For conventional as well as renewable technologies, we use the capital cost assumptions, shown previously, to assess the total value of each generating plant during the commissioning year. We then apply a straight line depreciation method to estimate the remaining economic value for every generation plant, assuming an economic life of 30 years for all technologies except batteries. For batteries, we use an economic life of 15 years. We use the average WACC of 5% (real), to annualize these costs of the existing capacity and then add them to our total costs.

Fuel Prices

In case of coal, we use province level monthly average coal prices delivered at power plants in the year 2019 (Figure B1). In order to be conservative, we assume that coal prices remain the same in real 2019 terms through 2035. In case of gas, we assume a flat price of $8/GJ between 2020 through 2035 based on the actual 2019 prices.

FIGURE B1. *Province level coal prices*



Source: http://www.imcec.cn/zgdm_2019.

TABLE B3. *Summary of Key Assumptions and Variables*

PARAMETER	ASSUMPTION	SOURCE
Geographic Scope	32 interconnected provinces	
Clean Technology Cost	BNEF projections	BNEF 2020
Operations & Maintenance (O&M)	Fixed and variable O&M costs of all non-retired power plants are included.	
Weighted Average Cost of Capital (WACC)	5%	Expert consultations
Energy Demand	National load forecasts based on Tsinghua's 2020 1.5C scenario, provincial shares of national demand, and monthly provincial generation shares	Tsinghua ICCSD, 2020
Extreme Events Analysis (Performed in PLEXOS)	Modeled highest net load (load minus wind and solar generation) week in the summer and winter in 2035, using 35 years of wind and solar data for China	
Technical Lifespan	Wind: 30 years Solar PV: 30 years Hydropower: 100 years Battery: 15 years Nuclear: 60-80 years Gas CT: 50 years Gas CCGT: 60 years	Expert consultations, He et al (2020)
Coal Retirements	Coal plants assumed to retire in 30 years in the coal retirement sensitivity	Expert consultations
Economic Lifespan	Standard amortization is 30 years, batteries are 15 years. No forced retirement of gas assets.	Expert consultations, He et al (2020)
Electrification of Buildings, Industry and Transport	Assumes growing reliance on electric vehicles, heating, and industry, per national load forecasts	Tsinghua ICCSD, 2020
Coal and Natural Gas Prices	Assume 2019 actual price remains constant through 2035	
Energy Policy	***Current Policy scenario:*** annual deployment of wind and solar limited to current government goals; 150 GW of net coal generation currently under construction is built. ***Clean Energy scenario:*** no new net coal generation capacity additions after 2020; non-fossil share of generation rises to 80% in 2035.	

APPENDIX C | PROVINCIAL HOURLY LOAD SHAPES

Hourly electricity demand data is not publicly available in China. To generate hourly provincial load shapes, we used publicly available data and an algorithm that disaggregates national electricity demand into hourly load profiles by province. These data include:

- National long-term load forecasts, based on policy and academic studies;
- Provincial shares of national electricity demand, based on a historical base year (2019);
- Monthly provincial generation shares, based on a historical base year (2019);
- Typical weekday and weekend/holiday load shapes by province, based on data from the NDRC.

Our disaggregation algorithm has four main steps.

Step 1: Disaggregate a national annual electricity demand forecast into provincial annual electricity demand forecasts

First, we disaggregate a national annual electricity demand (TWh/yr) forecast into provincial energy demands (PL_{iy} for province i) by multiplying a national load forecast in year y (NL_y) by forecasted provincial shares of national demand in year y (α_{yi})

$$PL_{yi} = \alpha_{yi} NL_y$$

The national electricity demand forecast, and by extension provincial forecasts, are for total electricity demand, including transmission and distribution losses, generator own-use, and behind-the-meter generation.

To be consistent with the level of expected electricity demand required to meet longer-term GHG emission reduction goals in China, we use as our base forecast the electricity demand projections from the 1.5°C scenario in the Institute of Climate Change and Sustainable Development's (ICCSD's) 2020 Low Carbon Development Strategy and Transition Roadmaps Study, with linear interpolation to fill in missing years. Table C1 shows the ICCSD forecast relative to other projections of long-term electricity demand in China.

TABLE C1. *Electricity Demand Projections Used in this Study and in Other Recent Studies*

STUDY / SCENARIO	2020	2025	2030	2035	2040	2045	2050
This study	7300	8350	9400	10745	12090	13435	14780
ICCSD (2020) / 1.5°C	7300		9400				14780
ICCSD (2020) / 2°C	7300		9400				13100
CNREC (2021) / Below 2°C	7736		11387	12740	13809	14889	15527
SGCC (2020) / Low range				11500			12400
SGCC (2020) / High range				12900			14700
EFC () / 1.5°C high	7285		10021	11228	12180	13913	15773
IEA (2020) / Stated policies		8891	9952		12023		
IEA (2020) / Sustainable dev.		8607	9317		10951		
Jiang (2018) / 2°C	7000	8500	9000		11000		12000
Jiang (2018) / 1.5°C	8000	9000	10000		13000		14000
CEC (2020)	7521	9500					

Provincial shares of national electricity demand will change over time, as a result of changes in population and economic structure. Changes in economic structure are difficult to account for; we are not aware of any long-term forecasts of provincial GDP in China that have sectoral detail. Longer-term provincial population forecasts are more widely available.

To forecast αyi, we multiply base year provincial per capita electricity consumption (EC_i) by long-term provincial population (PP_{yi}) forecasts from Chen et al. (2020) (SSP2 scenario), and then calculate αyi by dividing values for each province by the sum of all provinces.

$$\alpha_{yi} = \frac{EC_i \times PP_{yi}}{\sum_i EC_i \times PP_{yi}}$$

As Table C2 shows for 2035, changes in provincial shares of national electricity demand change only slightly relative to 2019.

TABLE C2. *Base and Projected Shares of National Electricity Demand*

PROVINCE	2019	2035
Beijing	1.61%	1.53%
Tianjin	1.21%	1.15%
Hebei	5.32%	5.29%
Shanxi	3.12%	3.12%
Inner Mongolia	5.04%	5.01%
Liaoning	3.31%	3.18%
Jilin	1.08%	1.02%
Heilongjiang	1.37%	1.29%
Shanghai	2.16%	2.07%
Jiangsu	8.64%	8.42%
Zhejiang	6.49%	6.29%
Anhui	3.17%	3.10%
Fujian	3.31%	3.31%
Jiangxi	2.12%	2.20%
Shandong	8.58%	8.21%
Henan	4.64%	5.00%
Hubei	3.05%	3.04%
Hunan	2.57%	2.55%
Guangdong	9.24%	9.57%
Guangxi	2.63%	2.84%
Hainan	0.49%	0.56%
Chongqing	1.60%	1.45%
Sichuan	3.64%	3.33%
Guizhou	2.13%	2.34%
Yunnan	2.50%	2.56%
Tibet	0.11%	0.10%
Shaanxi	2.64%	2.57%
Gansu	1.78%	1.80%
Qinghai	0.99%	0.99%
Ningxia	1.50%	1.62%
Xinjiang	3.96%	4.49%

Step 2: Disaggregate provincial annual electricity demand forecasts into provincial monthly electricity demand forecasts

We disaggregate annual provincial electricity demand (PLyi) into monthly provincial demand (PLmyi) using historical (2019) shares of monthly demand (βmi)

$$PL_{myi} = \beta_{mi} PL_{yi}$$

$$\beta_{mi} = \frac{PL_{mi}}{\sum_m PL_{mi}}$$

Data (2019) for βmi are from the Statistical Yearbook series.

Step 3: Disaggregate provincial monthly electricity demand forecasts into provincial hourly electricity demand forecasts

We disaggregate provincial monthly electricity demand to provincial hourly demand using typical weekday and weekend/holiday load shapes by province, published by NDRC (2021). This disaggregation involves two sub-steps: (1) calculating daily electricity demand for weekdays and weekends/holidays in each month; and, (2) multiplying daily electricity demand by normalized hourly load shapes.

We estimate provincial daily electricity demand for weekends/holidays (WEmyi) and weekdays (WDmyi) using the ratio of weekday and weekend/holiday consumption (θi for province i) from the NDRC load shapes and the number of weekends/holidays (DE) and weekdays (DD) in each month. For weekends, daily electricity demand is

$$WE_{myi} = \frac{PL_{myi}}{\theta_i \times DD + DE}$$

$$\theta_i = \frac{WD_{myi}}{WE_{myi}}$$

The value of θi is estimated from the daily totals of the NDRC typical weekday and weekend/holiday load shapes.

For weekdays, daily electricity demand is then:

$$WD_{myi} = \frac{PL_{myi} - WE_{myi} \times DE}{DD}$$

For each hour on weekdays and weekends/holidays, we calculate electricity demand using daily weekday and weekend/holiday loads and normalized shapes based on the NDRC load shapes. For each weekday, the hourly load shape (PLWDhmyi) is

$$PL_{hmyi}^{WD} = \varphi_{hi}^{WD} \times WD_{myi}$$

where the normalized load shape coefficients (φWDhi) are calculated using the NDRC typical weekday load shapes (LNWDhi)

$$\varphi_{hi}^{WD} = \frac{LN_{hi}^{WD}}{\sum_h LN_{hi}^{WD}}$$

For each weekend/holiday, the hourly load shape (PLWEhmyi) is similarly:

$$PL_{hmyi}^{WE} = \varphi_{hi}^{WE} \times WE_{myi}$$

Each weekday and weekend/holiday in a given month will thus have the same hourly values. We calculate annual hourly load shapes for each province by matching these hourly values to weekdays and weekends/holidays in each month in a given future model year (2025, 2030, 2035). We adjust holiday dates to match the future year.

Step 4: Adjust provincial hourly electricity demand forecasts to match a peak demand forecast

The provincial hourly electricity demand forecasts that result from steps 1-3 will be consistent with forecasted energy (TWh) demand but will generally not match peak (GW) demand. To reconcile the provincial hourly electricity demand forecasts with peak demand, we use a novel adjustment technique that scales the highest demand hour in a load duration curve (LDC) to match peak demand and pivots the rest of the LDC to ensure that the total area under the LDC matches total annual electricity (energy) demand.

To obtain the final LDC (FLhy), the initial LDC in hour h (ILhy) is adjusted by a peak adjustment factor (ωy in year y) and a scaling factor (γy):

$$FL_{hy} = IL_{hy} \times \left(\omega_y + \gamma_y[h-1]\right)$$

where ωy is the ratio between a peak load estimate based on a target system load factor (SLFy in year y) and the maximum value implied by the provincial load shapes above (max[PLhmyi])

$$\omega_y = \frac{\frac{\sum_h IL_{hy}}{H_y \times SLF_y}}{max\left(PL_{hmyi}\right)}$$

The scaling factor is:

$$\gamma_y = \frac{\left(\sum_h IL_{hy}\right) \times \left(1 - \omega_y\right)}{\sum_h L_{hy} \times (h - 1)}$$

The NDRC load shape data also includes a highest load and lowest load day, though it is not clear what these data represent; for instance, are they total electricity generation, inclusive of transmission and distribution losses, generator own use, and behind-the-meter generation (全社会用电量) or are they only end-use consumption? To ensure consistency, we use the maximum value in our load shapes in 2019 as a base year peak demand value and increase peak demand over time by using an algorithm for system load factor (SLF) declines.

Our algorithm for SLF declines assumes that provincial SLFs decline by 10% by 2025, 15% by 2030, and 20% by 2035, relative to the implied peak in the hourly load shape (PLWDhmyi). We use 50% as an SLF floor for all provinces. These assumptions lead to a roughly 20% decline in the average national SLF by 2035. Table C3 shows estimated SLFs provincial and national SLFs in 2035 and, for reference, 2019.

TABLE C3. *Estimated Provincial and National SLFs in 2019 and 2035*

PROVINCE	2019	2035
Beijing	0.55	0.50
Tianjin	0.71	0.58
Hebei	0.78	0.66
Shanxi	0.87	0.68
Inner Mongolia	0.95	0.72
Liaoning	0.88	0.69
Jilin	0.82	0.65
Heilongjiang	0.85	0.66
Shanghai	0.66	0.57
Jiangsu	0.73	0.56
Zhejiang	0.65	0.51
Anhui	0.72	0.56
Fujian	0.68	0.61
Jiangxi	0.74	0.58
Shandong	0.88	0.65
Henan	0.67	0.59
Hubei	0.72	0.57
Hunan	0.77	0.58
Guangdong	0.55	0.51
Guangxi	0.85	0.62
Hainan	0.73	0.65
Chongqing	0.61	0.52
Sichuan	0.78	0.56
Guizhou	0.74	0.63
Yunnan	0.96	0.67
Tibet	0.75	0.65
Shaanxi	0.89	0.59
Gansu	0.94	0.72
Qinghai	0.94	0.76
Ningxia	0.93	0.72
Xinjiang	0.88	0.71
National	0.78	0.62

APPENDIX D | SOLAR AND WIND PROFILES

We estimated the solar and wind (offshore and onshore) resource potential and profiles from the ground up. This section explains the methodology used which can be divided into two parts. The first part involves estimating the total resource potential of solar and wind available in each province. This forms an upper limit on the amount of new capacity that can be built in PLEXOS for each province. To estimate resource potential, we use the capacity factor data along with multiple exclusion datasets including land cover, elevation and slope of terrain. The second part involves estimating the representative hourly solar and wind profiles for each province. Profiles are estimated at site level using meteorological data from reanalysis datasets and then an aggregation algorithm is used to create a provincial representative profile.

RESOURCE POTENTIAL

Solar

To estimate the solar resource potential in each province, we start with the complete area of that province and remove the areas which are not suitable for solar development. We use three exclusion criteria for estimating the solar resource potential: land cover, slope and elevation. The land cover dataset comes from the European Space Agency's Copernicus programme. We use the Moderate dynamic Land Cover Dataset which has a spatial resolution of 100m and divides land cover into 23 classes. We exclude dense forest (i.e., forests with canopy > 70%), wetlands, moss and lichens, urban and built up areas, areas with snow and ice, permanent water bodies and open seas. In addition to land cover we use elevation and slope to remove areas not suitable for solar development. The elevation data also comes from the European Space Agency's Copernicus programme, the Copernicus GLO-30 Digital Elevation Model. The dataset has a spatial resolution of 30m and provides elevation of the surface of earth including man made buildings and infrastructure. We estimate slope from the elevation dataset using the planar method. The method estimates the steepest descent based on the maximum change in elevations between the cell and the 8 neighboring cells (Burrough, 1998). We exclude areas which have an elevation of more than 4000m and slope above 5 degrees. After exclusions based upon land cover, elevation, and slope, the areas that are left in a province are considered suitable for solar development.

To estimate the quality of solar resource potential in each province, we use the resource data from Global Solar Atlas. Solar Atlas provides annual average solar capacity factors at 30 arcsec (~1 km) spatial resolution. This dataset and its wind counterpart Global Wind Atlas were developed by the World Bank. Solar Atlas models solar generation using 10 years of meteorological data and creates an averaged solar capacity factor data. We combine the capacity factor data with the RE suitability data derived, after exclusions, to create a solar resource map of China (Figure D1) This map shows the capacity factor at all developable sites in China.

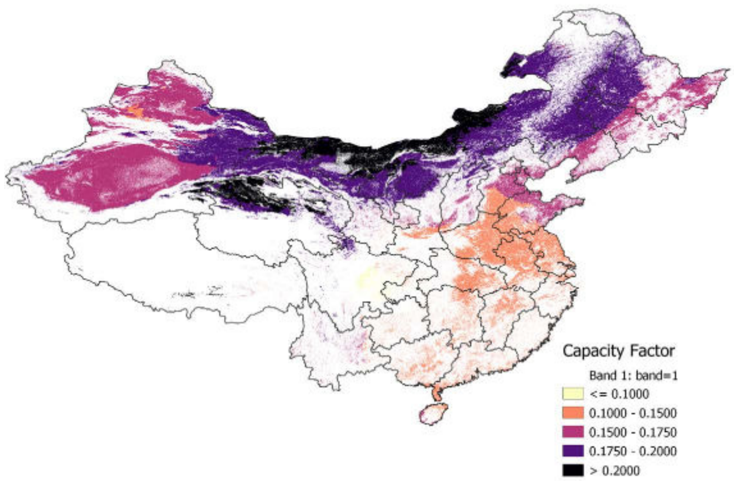


FIGURE D1. *Estimated solar capacity factors in China*

TABLE D1. *Estimated cumulative Solar Capacity by Capacity Factors*

CAPACITY FACTOR (CF)	CAPACITY ABOVE CF (GW)
0.24	7
0.22	135
0.2	16,212

Note: capacity shown is cumulative capacity above the specified capacity factor.

ONSHORE WIND

The methodology for estimating onshore wind resource potential is very similar to the method used for solar. We take the complete area of a province and remove the areas not suitable for wind development to estimate the resource potential. We use the same land cover, elevation, and slope datasets from the European Space Agency as used for solar. However, we use different limits on elevation and slope as solar and wind have different slope and elevation considerations. We exclude areas with elevation greater than 3000m and slope greater than 11.31 degrees for onshore wind. For land cover, we use the same criteria as solar and remove dense forests (i.e., forest with canopy > 70%), wetlands, moss and lichens, urban and built up areas, areas with snow and ice, permanent water bodies and open seas.

Global Wind Atlas provides the annual average wind capacity factors at 1 km spatial resolution. It was created using 10 years of hourly meteorological data and then averaged to get an annual average capacity factor for a site. We combine the Wind Atlas capacity factor data with our developable sites data to get a wind resource map of China (Fig. D2). This map shows the wind capacity factors at all developable sites in China.

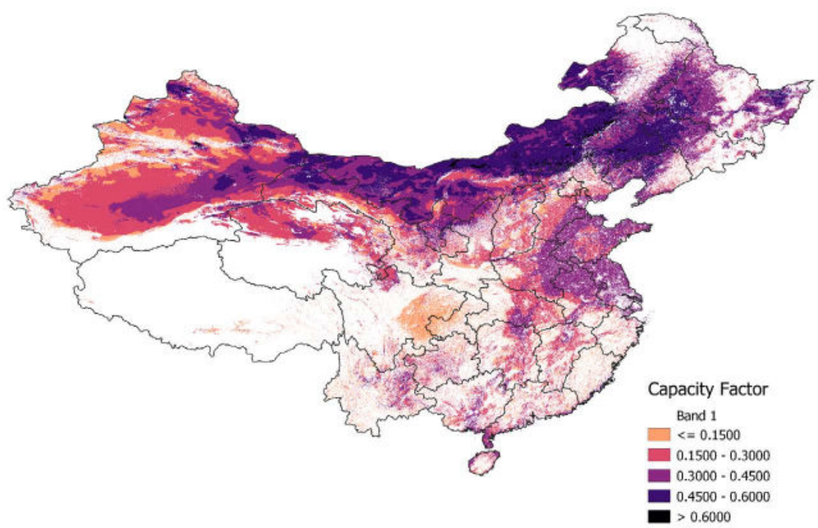


FIGURE D2. *Estimated Wind Capacity Factors in China*

TABLE D2. *Estimated Cumulative Onshore Wind Capacity by Capacity Factors*

CF	CAPACITY ABOVE CF (GW)
0.5	531
0.45	1,410
0.4	3,035
0.35	4,773

Note: capacity shown is cumulative capacity above the specified capacity factor.

OFFSHORE WIND

To estimate the offshore wind resource potential, we use the map of the exclusive economic zone (EEZ) of China and ocean depth data. We surprisingly know very little about the topography of our oceans, even less than the topography of Mars. The best global bathymetry dataset available is from the General Bathymetric Chart of the Oceans (GEBCO). GEBCO dataset has global coverage and has a spatial resolution of 500m. We start with a map of the EEZ of China and remove sites with ocean depth greater than 1000m. We assume that sites with depth greater than 1000m are currently not economically developable for offshore wind. The sites with ocean depth less than 60m are suitable for fixed bottom technology and the sites with ocean depth between 60 and 1000m are assumed to be suitable for floating wind technology. These limits on technology suitability are derived from National Renewable Energy Laboratory (NREL) which uses the same limits for the U.S. As we did for solar and wind, we combined this dataset with the capacity factor data from the Global Wind Atlas to create an offshore wind resource map for China, showing the capacity factor at all developable offshore locations (Fig. D3).

FIG D3. *Estimated offshore wind capacity factors in China*

TABLE D3. *Estimated cumulative Offshore Wind Capacity by Capacity Factors*

CF	CAPACITY ABOVE CF (GW)
0.55	214
0.50	797
0.45	1,447
0.35	4,773

Note: capacity shown is cumulative capacity above the specified capacity factor.

MODELING RESOURCE PROFILES

Here we talk about the methodology used to create representative solar and wind hourly generation profiles for each province. We use the resource map dataset created in the previous section, the dataset with capacity factors at developable sites. In addition, we use meteorological data from reanalysis datasets. We extract wind speed, pressure, temperature, solar irradiance etc. from reanalysis datasets and pass them through a software which models wind farms and solar parks and get hourly solar and wind generation as outputs. Several sites in a province are aggregated to create a representative generation profile for each province. The methodology for solar, onshore wind and offshore wind is discussed in detail below.

Solar

In the previous section, we created a gridded dataset of developable sites with annual average capacity factors. That gave us a technical resource potential, but not all sites which can be technically developed would actually be developed. The quality of resources drives the economics and only the best resource sites actually get developed. To get a representative resource profile for each province, we need to find a sample of the best sites and aggregate their individual profiles. For estimating the solar profile, we filter out the top 20 percentile of the sites with the highest capacity factor. To ensure that we do not select very low capacity factor sites we only keep sites with capacity factor greater than 15%. From this pool of top sites in a province, we randomly select 2000 sites. We then estimate hourly generation at each of these 2000 sites and average them to create a representative solar profile for the province.

Hourly meteorological data from ERA5 is used to estimate hourly generation at each of the 2000 sites. ERA5 is a hourly reanalysis dataset from European Centre for Medium-Range Weather Forecasts (ECWMF) and has a spatial resolution of 30 km x 30km. ERA5 provides historical hourly data on wind speed, temperature, pressure, solar radiation etc. at 137 pressure levels from surface up to a height of 80km.

To estimate solar generation, we extract the surface solar radiation downwards (ssrd), temperature at 2m and u and v component of wind speed at 10m height. To model solar generation at a site, we also need Direct Normal Irradiance (DNI) and Direct Horizontal Irradiance (DHI). The ssrd variable from ERA5 gives the Global Horizontal Irradiance (GHI), and we use GHI to estimate DHI and DNI. NREL's DISC model provides empirical relationships between GHI and DHI, GHI and DNI, based on Maxwell, 1987.

NREL's System Advisor Model (SAM) is used to model solar generation. The SAM software development kit takes GHI, DHI, DNI, temperature, u and v wind components as inputs and outputs solar generation. We use a single axis system to simulate solar generation using SAM. The hourly generation at 2000 sites is averaged to create a representative profile for the province.

Onshore Wind

The methodology for estimating onshore wind profiles is very similar to solar, and a similar method is used to select sample sites in each province. We filter the top 20 percentile of sites from the annual average capacity factor dataset developed while estimating resource potential. To avoid very low capacity factor sites, we remove sites with capacity factor of less than 30%. From this we randomly select 2000 sites.

We simulate hourly generation for a year for each of these 2000 sites using the SAM model. We model a wind farm with 32 turbines, arranged in a 8 x 4 rectangular shape. SAM takes wind speed at the hub height of the turbine, wind direction, surface pressure and temperature as inputs and gives hourly farm generation as output. Meteorological data is taken from ERA5. It provides wind speed at 10m and 100m which are then scaled to the hub height of the wind turbine used, and surface pressure and temperature are also available from ERA5. The spatial resolution of ERA5 is 30 km, which is quite high for modeling wind speed as winds can vary significantly by local topography.

To account for some of the effects of local topography, we use the average wind speed data from Wind Atlas which has a much higher spatial resolution of 1km x 1 km. We create a scaling factor using the average wind speed data from Wind Atlas and average wind speed data from ERA5. We scale the hourly wind speeds in ERA5 by this factor to get a more accurate wind speed profile. Corrected wind speeds are passed through to SAM to get hourly generation. The hourly generation from 2000 sites is averaged to get a representative profile for the province.

Offshore Wind

Since there are no predefined provincial boundaries for offshore wind we have to create artificial zones to get representative profiles. For this purpose, we divide the entire coast of China into 5 equal latitude size zones. Sites lying within each region belong to that zone. From this, we will get 5 representative offshore wind profiles. We sample 2000 sites in each of the zones using the same methodology used for onshore wind and solar. We filter the top 20 percentile of sites with the highest capacity factor and keep the minimum capacity factor to 30%. We simulate hourly generations at each site using SAM. Wind speed and direction at hub height, temperature and pressure data is required for simulating wind generation in SAM.

For offshore wind we used meteorological data from U.S. National Aeronautics and Space Administration (NASA)'s Modern-Era Retrospective analysis for Research and Applications (MERRA2) dataset which has a spatial resolution of 0.5 deg x 0.625 deg. MERRA2 data is shown to have better accuracy for offshore wind speeds than ERA5, for this reason, we select MERRA2 despite it having much lower spatial resolution compared to ERA5. A scaling factor is used again to account for spatial downscaling as done for onshore wind. The hourly generation from the 2000 sites is aggregated to create a representative profile for each zone.

APPENDIX E | HEALTH IMPACT MODELING

A reduced-form air quality model, InMAP-China, and a concentration-response function developed for China are used to quantify the premature deaths caused by ambient $PM_{2.5}$ concentrations associated with those power plants' emissions (SO_2, NO_x, and $PM_{2.5}$ emissions) in China (Wu et al., 2021; Yin et al., 2017). We respectively calculate the annual average capacity factor of coal and natural gas-fired power plants in each region and estimate the annual emissions from each power plant based on the average capacity factor and emission rates from Yang et al. (2019).

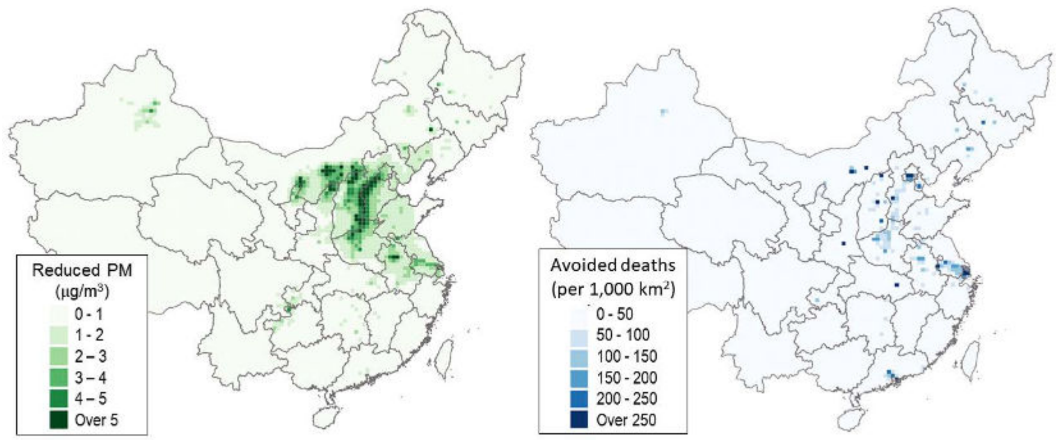
We quantify the premature deaths caused by all sector emissions except for the power sector emissions as the baseline and then quantify the total mortalities from all sectors including the power sector emissions under all proposed scenarios. Therefore, the differences between the baseline and the all-sector mortalities are the premature deaths caused by power plant emissions in China. Population increase is not considered in this analysis and all mortality changes are caused by emission changes.

Table E1 below shows that the Clean Energy scenario can help reduce negative health impacts associated with power plant emissions by more than 50% in 2035 due to less generation from the burning of fossil fuels. Figure E1 shows that PM concentrations drop significantly in northern and eastern China under the Clean Energy Scenario in 2035. Due to the high population density, regions like Beijing, Hebei, and Jiangsu enjoy dramatic health benefits from the Clean Energy scenario.

TABLE E1. *Premature deaths associated with power plant emissions in China in 2020, 2025, and 2035 under Current Policy and Clean Energy scenarios. (Percentages are the mortality reductions compared with the Current Policy case.)*

<table>
<tr><th></th><th>2020</th><th>2025</th><th>2035</th></tr>
<tr><td>Current Policy</td><td rowspan="2">118,430</td><td>130,060</td><td>104,720</td></tr>
<tr><td>Clean Energy</td><td>115,380 (12%)</td><td>50,560 (52%)</td></tr>
</table>

FIGURE E1. *Spatial distribution of PM concentration reductions (left) and avoided mortalities (right) caused by power plant emissions under the Clean Energy scenario when compared with the Reference scenario in 2035.*



APPENDIX F | EMPLOYMENT IMPACT MODELING

CHANGES IN CLEAN ENERGY DEPLOYMENT AND SPENDING

We used output data on clean energy technology deployment and demand from the capacity expansion model and a customized version of the China Energy Policy Simulator (China EPS) to estimate employment impacts. To do so, we hard coded the outputs from the capacity expansion modeling into the input-output model embedded in the China EPS. Impacts are expressed as a difference between the Current Policy and Clean Energy scenarios, not an absolute change from 2020-2030, isolating the impact of an 80% clean electricity policy on employment.

INPUT-OUTPUT MODELING

Estimates of labor impacts from clean energy policies in China are made using an embedded input-output (IO) macroeconomic model in the China EPS. The IO model receives data from other parts of the model on changes in cash flows for capital, fuel, maintenance, labor, etc and flows these through a typical IO model structure to estimate changes in direct, indirect, and induced economic impacts. Macroeconomic feedbacks are accounted for on a single year delay. More information on the IO model embedded in the EPS can be found online here: https://us.energypolicy.solutions/docs/io-model.html

KEY PARAMETERS

The IO model is populated with publicly available data, much of which comes from the Organisation for Economic Co-operation and Development (OECD). Key input data include business-as-usual employment, output, and value added, estimates of the Domestic Leontief Inverse Matrix (which relates outputs from an industry to the inputs required to produce output and is used to estimate indirect effects), and labor productivity growth rates. Labor productivity in particular has a very strong effect on the magnitude of employment impacts, and several scenarios were assessed for this modeling.

LABOR PRODUCTIVITY GROWTH RATE ESTIMATES

We evaluated three different scenarios for labor productivity growth in China in this analysis:

- Holding constant productivity at today's levels (Zero Future Growth Scenario)
- Continued growth in productivity based on the greatest amount of historical data dating back to 2000, while looking at manufacturing as a whole (Maximum Historical Growth Scenario)
- Continued growth in productivity based on the greatest amount of historical data dating back to 2000 but looking at individual industries within the manufacturing sector (Maximum Growth with Manufacturing Industries Scenario)

The employment results in the main text of this report represent this final scenario, and use both the sector-by-sector labor productivity growth rate index based on historical data shown in Figure F1, with the manufacturing broken down by industry as shown in Figure F2.

In the Zero Future Growth Scenario, we assumed no incremental productivity growth beyond today's productivity. This scenario should be viewed as an upper bound on potential employment impacts, because future labor productivity gains (or losses) are not accounted for, and changes in spending therefore yield larger changes in employment than in other scenarios. There is a net gain of 4.3 million job-years in this scenario, with 13.1 million job-years gained over all sectors, 5.3 million job-years lost in the coal mining sector, and 3.4 million job-years lost in all other sectors combined, as shown in Figure F3.

In the Maximum Historical Growth Scenario set, we relied on as many years of data as possible back to 2000 to produce future growth estimates, shown in Figure F1. There is a net gain of 1.2 million job-years in this scenario, with 4.1 million job-years gained over all sectors, 1.7 million job-years lost in the coal mining sector, and 1.1 million job-years lost in all other sectors combined, as shown in Figure F4.

In the Maximum Growth with Manufacturing Industries Scenario, used in the main text of this report, we similarly relied on as many years of data as possible but used growth rates for individual manufacturing industries as available, as seen in Figure F2. There is considerable differentiation among industries, which is reflected in this dataset.

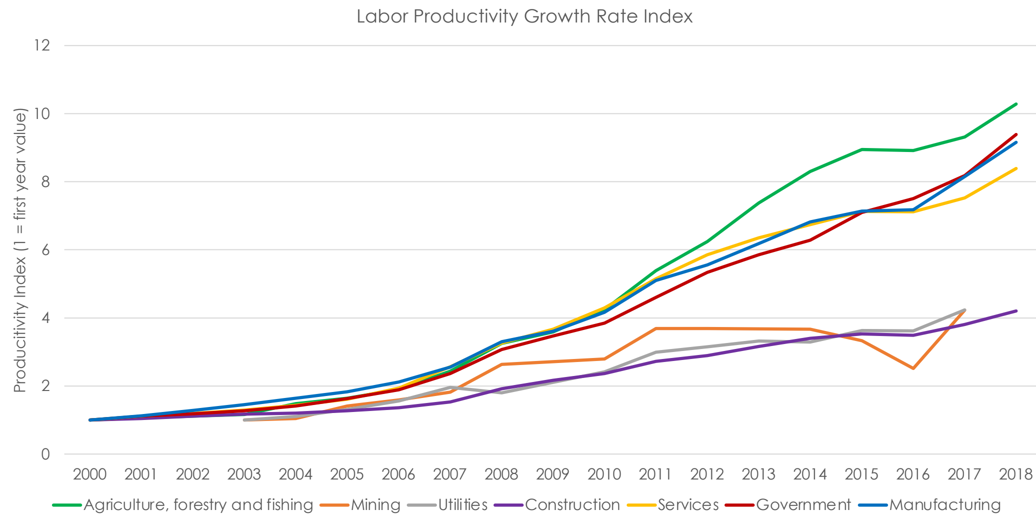


FIGURE F1. *Historical labor productivity growth rate index by sector in China.*

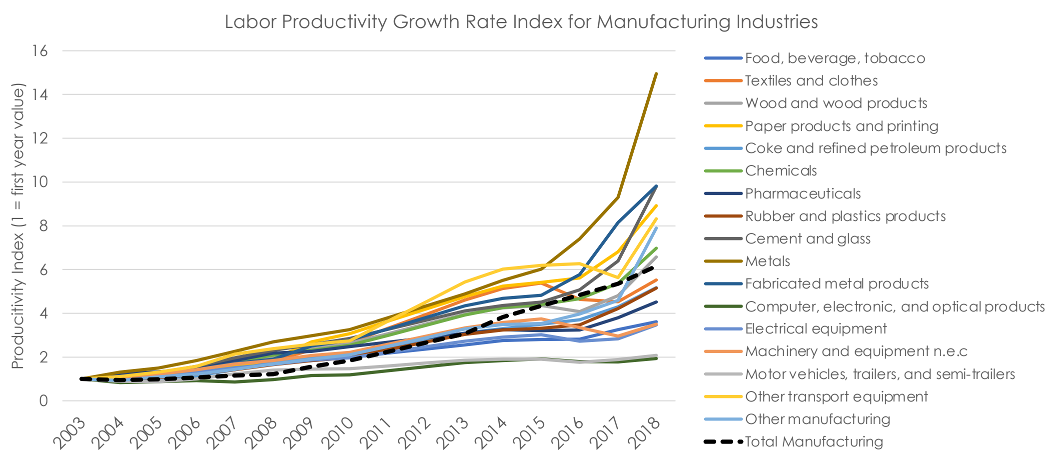


FIGURE F2. *Historical labor productivity growth rate index by manufacturing industry in China.*

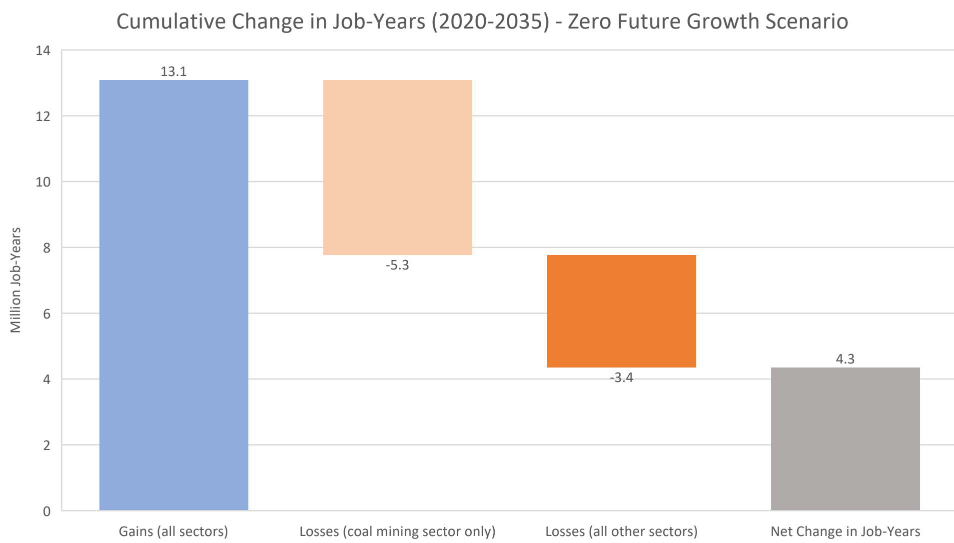


FIGURE F3. *Cumulative change in job-years when assuming no incremental growth in productivity. This is an upper bound on employment changes.*

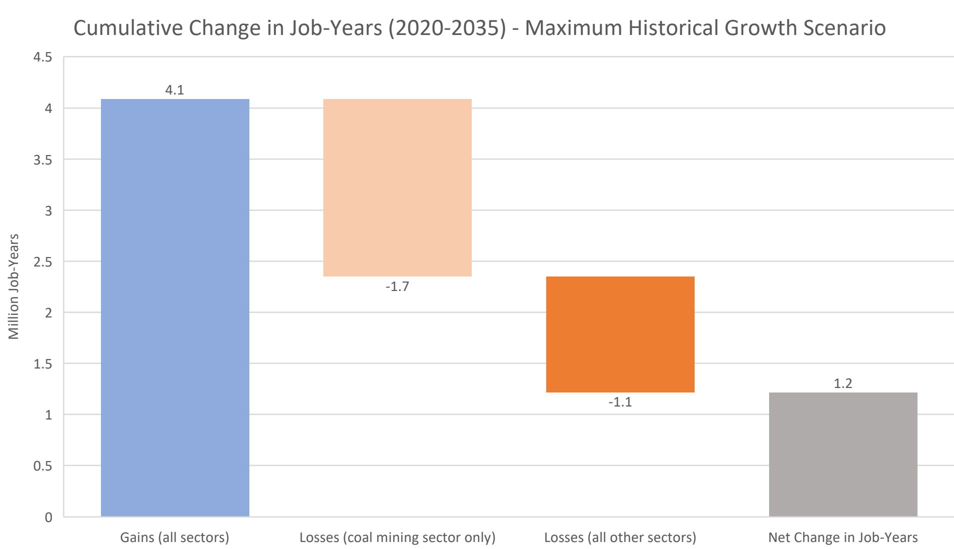


FIGURE F4. *Cumulative change in job-years using sector-by-sector labor productivity growth rate index estimates based on historical data.*