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CHINA ZERO-CARBON ELECTRICITY GROWTH IN THE 2020S:
A Vital Step Toward Carbon Neutrality

BY ROCKY MOUNTAIN INSTITUTE, ENERGY TRANSITIONS COMMISSION

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SUGGESTED CITATION

Yiyan Cao, Ji Chen, Bingqi Liu, Adair Turner, and Caroline Zhu, *China Zero-Carbon Electricity Growth in the 2020s: A Vital Step Toward Carbon Neutrality,* Energy Transitions Commission and Rocky Mountain Institute, 2021, **http://www.rmi.org/url here**.

All images from iStock unless otherwise noted.

ACKNOWLEDGMENTS

The authors thank the following individuals who contributed time and expertise to this research through interviews and support:

Clyde Loutan, California ISO
Louise Clark, UK National Grid
Mark Dyson, Rocky Mountain Institute

The team wants to thank the ETC Commissioners and the ETC network for their active contribution.

Special thanks to the Angela Wright Bennett Foundation, Bloomberg Philanthropies, ClimateWorks Foundation, Quadrature Climate Foundation, Sequoia Climate Fund, and The William and Flora Hewlett Foundation for their support of this report.

** Organizations listed alphabetically.*

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ABOUT ENERGY TRANSITIONS COMMISSION

The Energy Transitions Commission (ETC) is a coalition of global leaders from across the energy landscape: energy producers, energy-intensive industries, equipment providers, finance players, and environmental NGOs. Our mission is to work out how to build a global economy that can both enable developing countries to attain developed world standards of living and ensure that the world limits global warming to well below 2°C and as close as possible to 1.5°C. For this objective to be reached, the world needs to achieve net-zero greenhouse gas emissions by around mid-century.

ROCKY MOUNTAIN INSTITUTE

ABOUT ROCKY MOUNTAIN INSTITUTE

Rocky Mountain Institute (RMI)—an independent nonprofit founded in 1982—transforms global energy use to create a clean, prosperous, and secure low-carbon future. It engages businesses, communities, institutions, and entrepreneurs to accelerate the adoption of market-based solutions that cost-effectively shift from fossil fuels to efficiency and renewables. RMI has offices in Basalt and Boulder, Colorado; New York City; Oakland, California; Washington, D.C.; and Beijing.

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1 INTRODUCTION

INTRODUCTION

At the United Nations on September 22, 2020, President Xi Jinping committed China to achieve carbon neutrality before 2060 and to peak emissions before 2030.[1] This was a hugely important step forward in the international fight against climate change and reflects China's determination to provide responsible global leadership.

China can achieve carbon neutrality and become a fully developed, rich economy by 2060 and potentially as early as by 2050. As outlined in two recent reports by the Energy Transitions Commission, one focused on the global economy and one specific to China,[2] it is undoubtedly possible for technologically advanced economies to achieve zero carbon by mid-century at a very low economic cost.

The key to achieving this is to electrify as much of the economy as possible and to ensure that almost all electricity is generated with zero-carbon resources well before the target date for overall carbon neutrality. Countries around the world are increasingly focused on the need and opportunity to decarbonise electricity systems and are setting targets accordingly.

- The UK is now legally committed to achieve net-zero GHG emissions by 2050, with a goal to achieve a zero or near-zero carbon electricity system by 2035.
- President-Elect Biden proposes that the United States achieve a carbon-free power sector by 2035 and reach net-zero emissions no later than 2050.

A recent analysis from Tsinghua University's International Center for Climate Change and Sustainable Development (ICCSD) shows how China can meet the 2060 or earlier carbon neutrality target, aligned with limiting global warming to 1.5°C.

In all credible scenarios and in all countries, electricity decarbonisation has to lead the way to broader economy-wide decarbonisation. What happens in China's electricity system in the 2020s is therefore vital both to peak emissions before 2030 and to the credibility of the 2060 or earlier carbon neutrality target. China must significantly accelerate growth in zero-carbon power investment to be on a path to meet President Xi's objective. Any new coal investment threatens to create assets which will either make the target unattainable or will have to be closed down well before the end of their useful life. This would create a waste of investment resources and additional challenges to decarbonising the power system.

The appropriate strategy compatible with China's long-term carbon neutrality target should therefore be to ensure that moving forward almost all growth in China's electricity generating capacity is zero carbon, with no new coal investment. However, China is continuing to build new coal-fired plants with about 20 gigawatts (GW) approved from January to June 2020, which is higher than the total capacity permitted each year in the past four years.[i,3]

This reflects multiple factors, including actual or perceived incentives that encourage provinces to take actions incompatible with the national objective. One factor is the misguided belief that it is difficult or even technically impossible to integrate new renewable supply without additional coal supply. Another false assumption is that the zero-carbon electricity supply will not be able to grow fast enough to meet expanding demand in the 2020s. This report demonstrates why these beliefs are mistaken and why a policy of almost all new growth from zero-carbon sources is feasible and economically optimal.

By 2050 a largely decarbonised Chinese economy will consume about 15,000 terawatt-hours (TWh) of electricity, about double the current level. This will entail some sectors and activities that currently use fossil fuels—such as surface transport and residential heating—achieving close to full electrification. By

[i] The majority of the newly permitted projects are not replacements for retired smaller units.

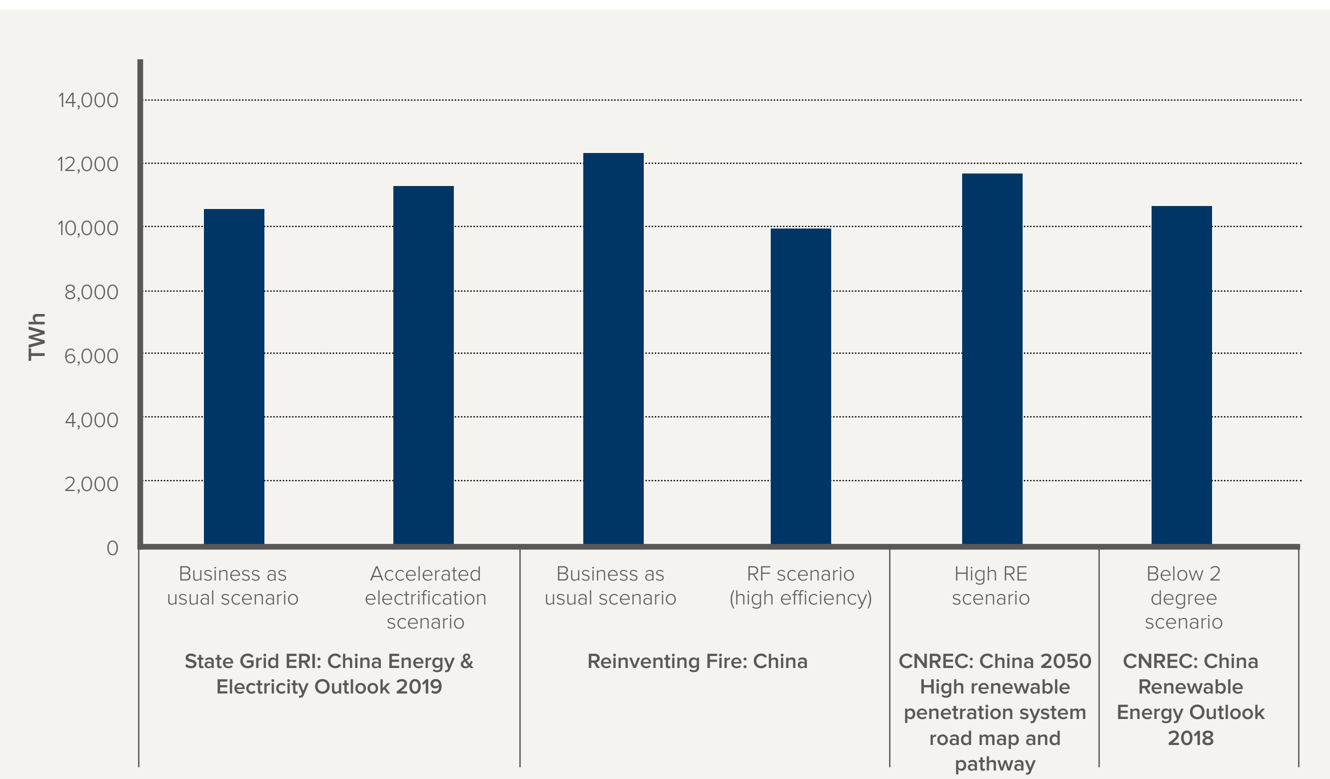
2030, studies suggest China's electricity demand will range from about 10,000 to 12,000 TWh as economic growth continues and as electrification spreads to new sectors (Exhibit 1).

In this report we therefore assess a scenario for 2030 aligned with what is needed to decarbonise China's power sector by 2050; we will refer to this as the Zero-Carbon Investment Scenario. This scenario, shown in Exhibit 2, includes the following assumptions:

- electricity supply reaches 11,000 TWh by 2030, an increase of 54% above current levels, reflecting an average growth rate of 4% per year;
- no new coal supply is added beyond the 1,041 GW in place in 2019, but with a slight increase in coal generation as existing assets are used more intensely;[ii]
- variable renewables capacity increases from 408 GW in 2019 to 1,650 GW in 2030—which equates to about 110 GW annually—with variable renewable generation accounting for 28% of total generation in that year; and
- total non-fossil fuel generation reaches 53% of the total, slightly above the target of 50% proposed by China's government in 2016.[4]

EXHIBIT 1

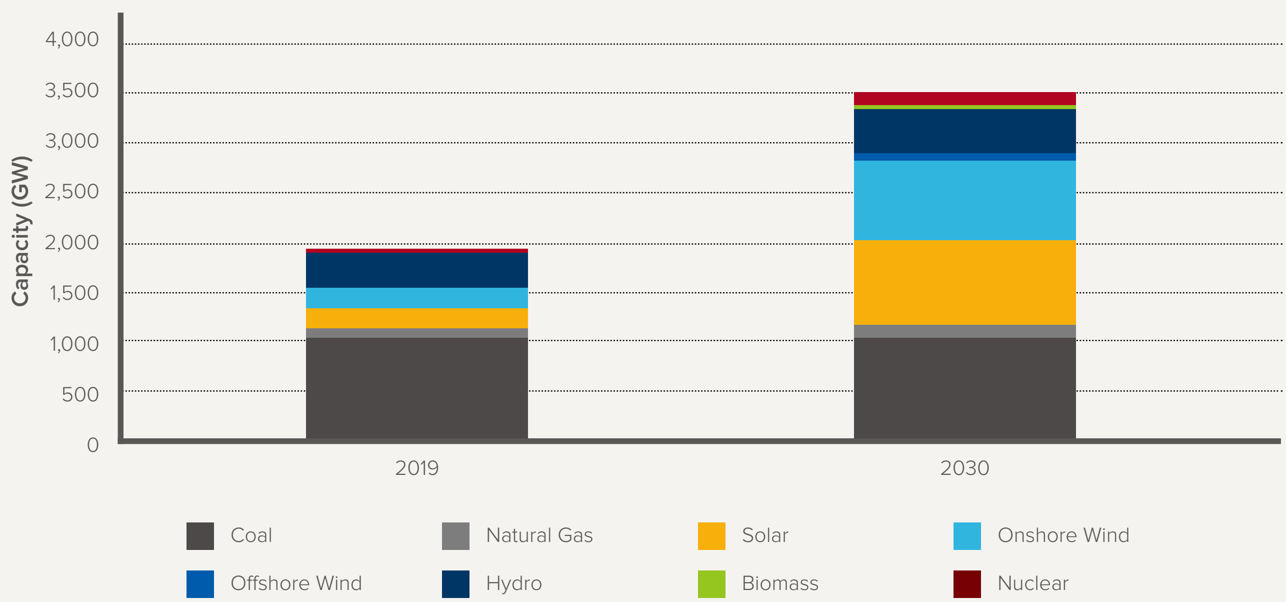
Comparison of China Electricity Demand in 2030

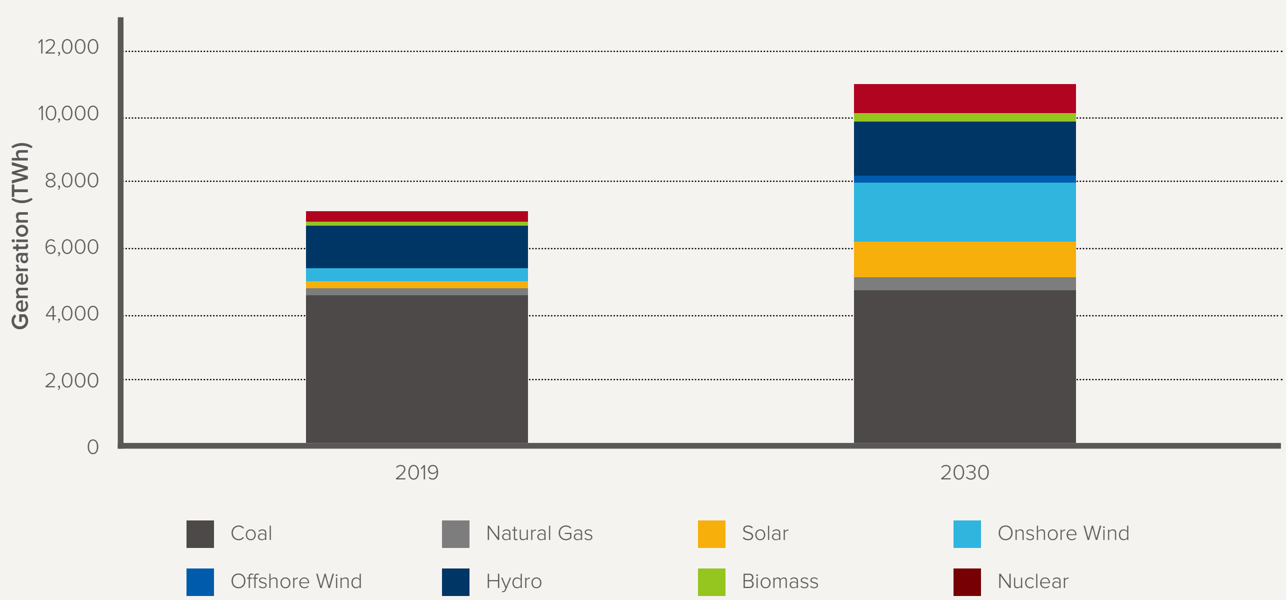


[ii] As construction of coal power plants currently underway adds new coal capacity, it is being offset by retiring smaller, inefficient units. However, the total capacity should not exceed the current amount of capacity, given increasing stranding risks.

EXHIBIT 2

Generation and Capacity Mix in 2030 under the Zero-Carbon Investment Scenario[iii]





[iii] The illustrated assumptions of the scenario are in the Appendix, Table A

This scenario would need to be followed by further rapid zero-carbon supply expansion from 2030 to 2050 and by the gradual elimination of existing coal generation—unless fitted with carbon capture and storage—during that timeframe. Achieving this scenario will help make the “peaking before 2030” objective attainable and put China on a path compatible with its 2060 objective.

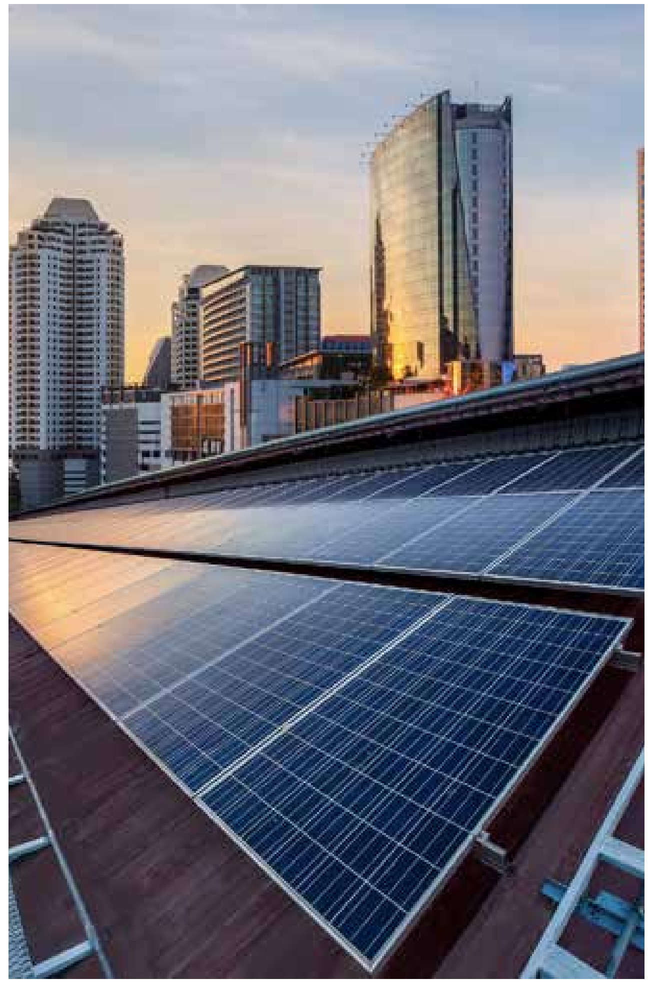
This paper describes why meeting the growth almost entirely from zero-carbon generation sources is feasible and what needs to happen to deliver it, in four sections.

1. The economic case for zero-carbon power and the path to low-cost green electricity

2. The technical feasibility of rapidly expanding variable renewable energy (VRE) generation

3. Approaches to successfully balancing supply and demand in a system with an increasing share of VRE

4. The policies required to deliver zero-carbon electricity growth through 2030 and beyond



2 THE ECONOMIC CASE FOR ZERO-CARBON POWER

THE ECONOMIC CASE FOR ZERO-CARBON POWER

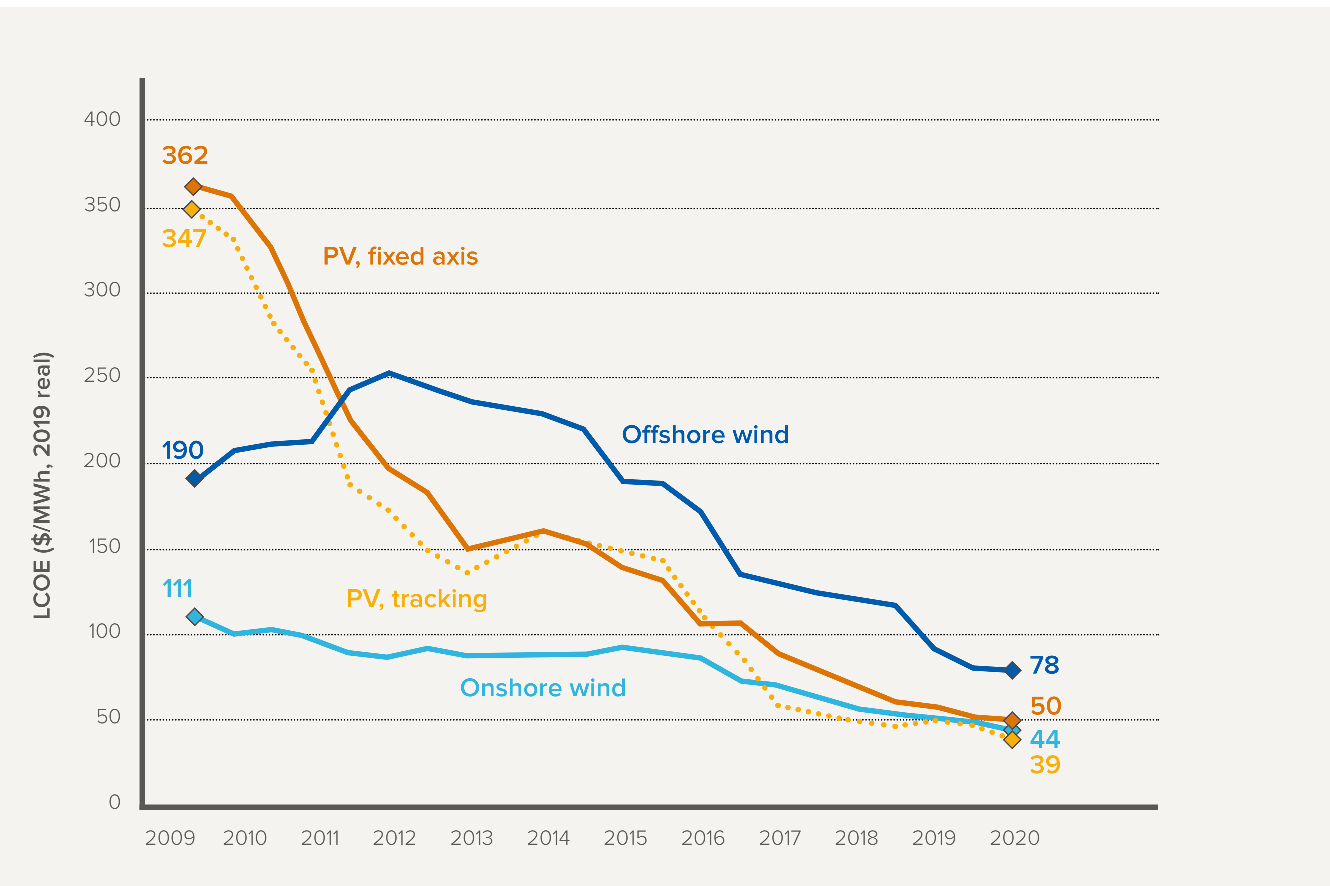
Across the world, renewable electricity generating costs are increasingly falling below those of fossil fuels, and this is true also in China. But China must adjust its policies to ensure that renewable costs continue to fall as rapidly as possible and zero-carbon investment grows as fast as needed.

RENEWABLES COSTS FALL ACROSS THE WORLD

The cost of renewable electricity generation has fallen dramatically over the past 10 years. Estimates of the global average levelized cost of electricity (LCOE) for solar are down 85%, onshore wind is down 60%, and offshore wind costs have now started a rapid fall, down over 60% in just five years.[5] In favourable locations bid auction prices have been far lower still. Thus, while the estimated average global LCOE for solar PV is about $50 per megawatt-hour (MWh), auctions in California, Portugal, and the Middle East have seen prices at or below $20/MWh. And while the global average offshore wind LCOE is estimated at about $90/MWh, a recent auction in the UK was closed at about $51/MWh.[6]

EXHIBIT 3

Global LCOE Benchmarks for Solar and Wind, 2009–2020

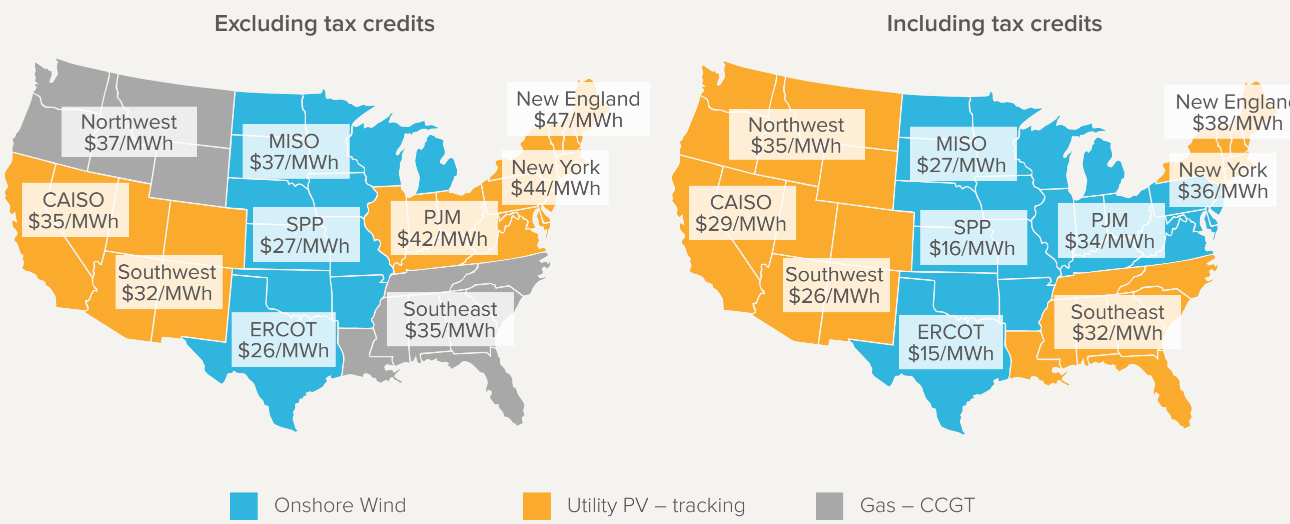


Source: BloombergNEF

In many countries, solar and wind are now competitive with baseload fossil fuel generation, and in some countries renewables plus storage is becoming a cheaper way to provide peaking power than gas turbines. Estimates for the United States show that solar or wind with tax credits are now cheaper than combined cycle gas turbine (CCGT) plants in all states (Exhibit 4), and in several US states orders for new gas peaking plants have been cancelled in favour of solar PV plus battery combinations.[7]

EXHIBIT 4

Cheapest Source of New Bulk Electricity in the United States, 2020



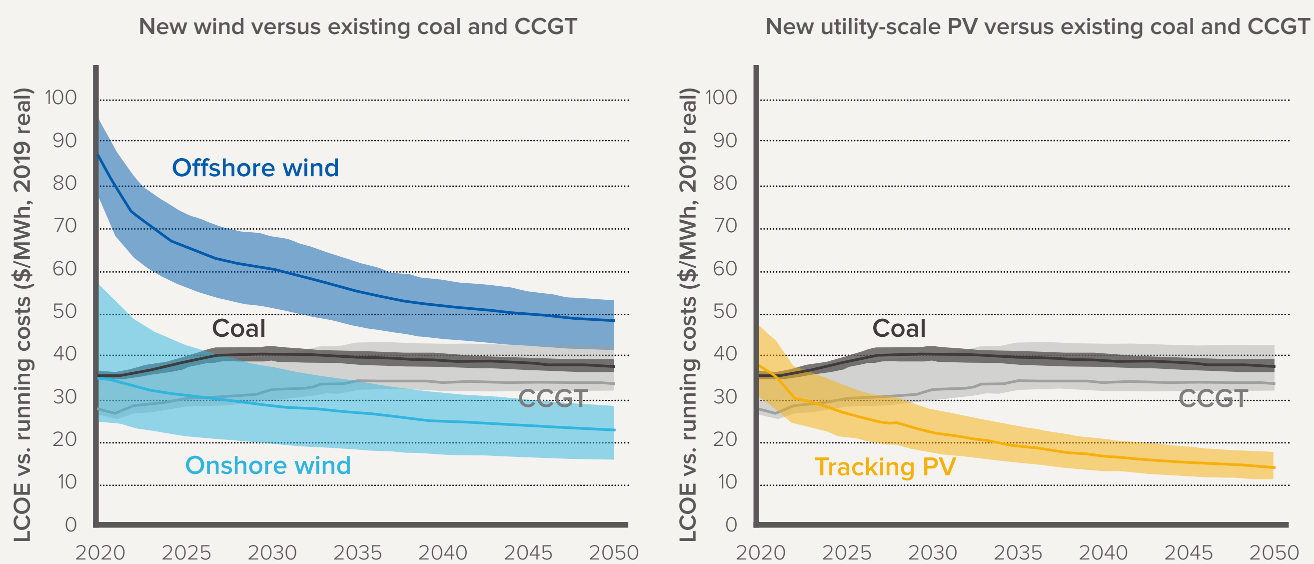
Note: Regions follow state boundaries and therefore do not map perfectly to ISO territories. The numbers represent the benchmark LCOE for each ISO.

Source: BloombergNEF

Looking forward, these cost reductions are certain to continue. As a result, solar and wind costs in some countries will soon fall below the marginal cost of running existing coal or gas plants. That tipping point will be reached in many countries during the 2020s, and the renewable energy advantage will steadily widen over time. Exhibit 5 outlines the cost trajectory in the United States where renewables are beginning to outcompete both new coal investments and many existing coal plants, putting additional pressure on these plants and the companies that own them.[8]

EXHIBIT 5

Economic Comparisons of New Renewables and Existing Fossil Generation in the United States



Note: All LCOE calculations exclude tax-credits and curtailment. The range of the LCOE represents a range of costs and capacity factors. In the case of offshore wind, our assessment includes the generating asset, the offshore substation, the export cable, and the onshore substation. For thermal plants, the short-run marginal cost range represents a diversity of plant efficiencies in the fleet.

Source: BloombergNEF

RENEWABLES AND OTHER ZERO-CARBON COSTS IN CHINA

The global picture is mirrored in China where solar costs are already falling below the cost of coal generation, and onshore wind will soon follow. Offshore wind costs will likely become competitive during the 2020s, and China's nuclear costs are broadly competitive with coal today.

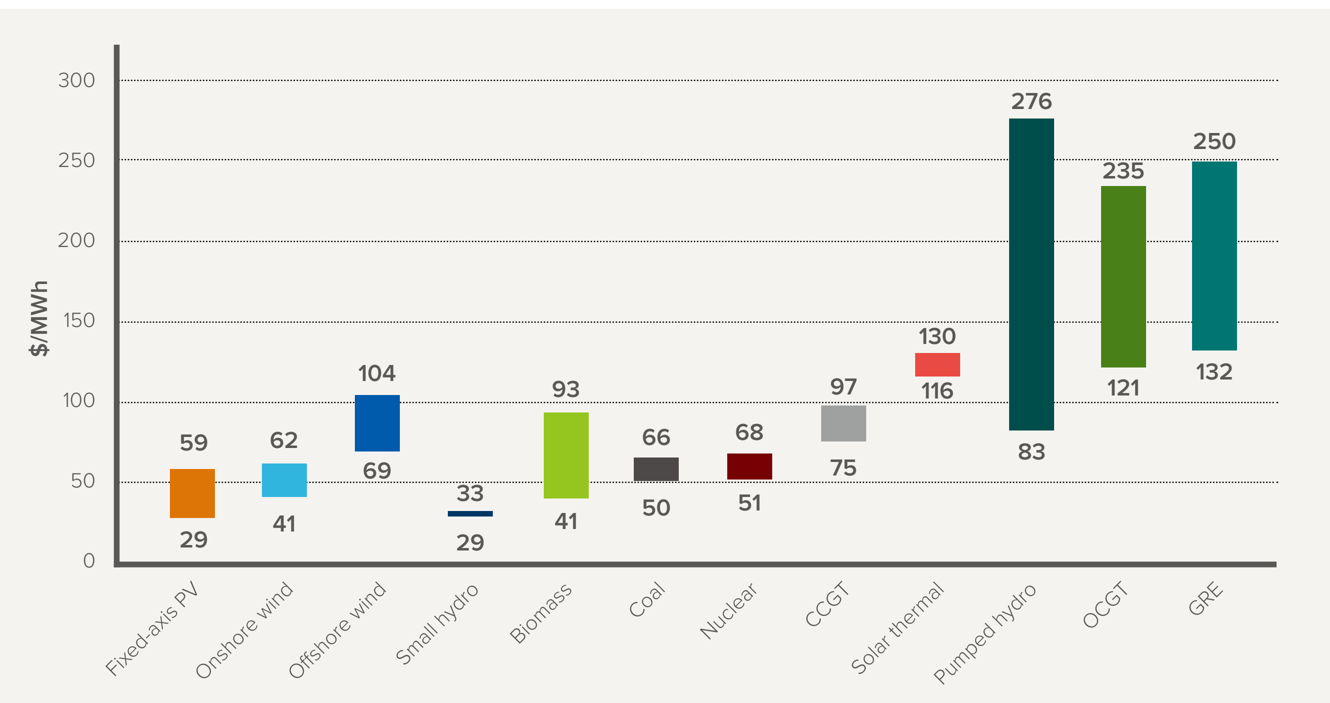
Solar costs already below new coal

Estimates from BloombergNEF (BNEF) suggest that the LCOE of solar in China is now between \$29/MWh and \$59/MWh, making it competitive with new coal in most locations (Exhibit 6).[9] Prior to 2019, solar costs were compensated via a fixed feed-in tariff that was designed to decline gradually over time. In 2019 China switched to an auction system. The latest permitting outcomes and auction results have broadly confirmed BNEF's estimates that solar is now competitive with new coal and will be increasingly competitive with existing coal.

Auction results in 2019 revealed a 30% reduction in solar costs compared to 2018 project costs, and 2020 brought a further 20% reduction, similar to BNEF's estimate of a 26% decline in LCOE.[iv] As a result, while the 2019 solar auction strike prices were still higher than the new coal benchmark price in most provinces, in 2020 the average subsidy had fallen to just \$5/MWh.[v] The lowest subsidies were just \$0.01/MWh (Exhibit 7).[10]

EXHIBIT 6

LCOE of Different Generation Sources in China, 2020



Source: BloombergNEF

[iv] Cost reduction rates are calculated based on auction results released by the National Energy Administration.

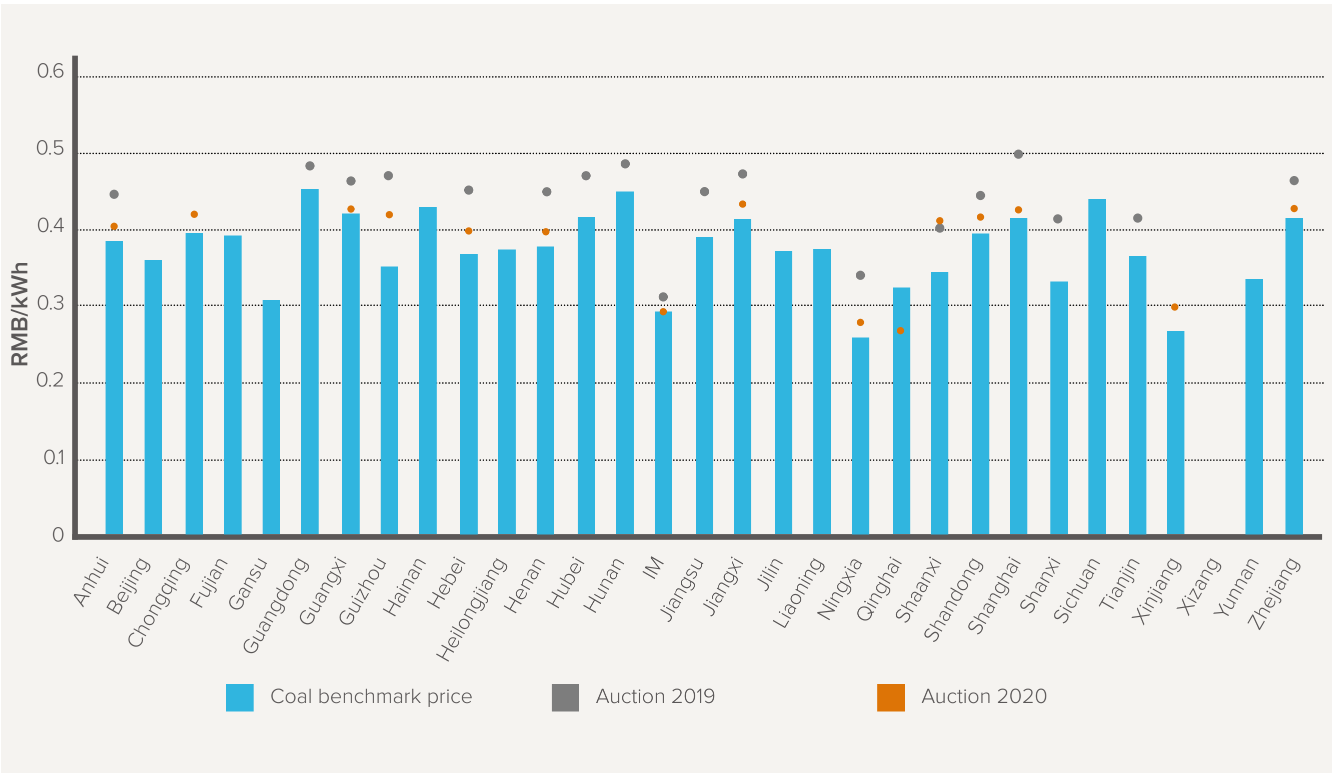
[v] The subsidy is the price premium paid to developers over coal benchmark price.

These cost reductions are certain to continue, and would imply attainable auction prices in 2021 significantly below the coal benchmark price in almost all provinces (Exhibit 8) and in many provinces below the coal transaction price (Exhibit 9).[vi] This is aligned with the market forecast that subsidies will no longer be available.

Solar subsidies are being phased out with solar costs becoming competitive enough to make unsubsidised projects economic. In 2020, 33 GW of new unsubsidised projects were approved and nearly 50 GW of unsubsidised solar is under development across 20 provinces.

EXHIBIT 7

Comparison of New Coal and Solar Auctions in China, 2020



[vi] Transaction prices are the prices for mid-to-long-term contracts and usually fall between marginal operating costs and all-in costs. This can provide insight into the costs of running existing plants.

EXHIBIT 8

Comparison of New Coal, 2020 Solar Auctions, and Feasible 2021 Solar Prices in China[vii]

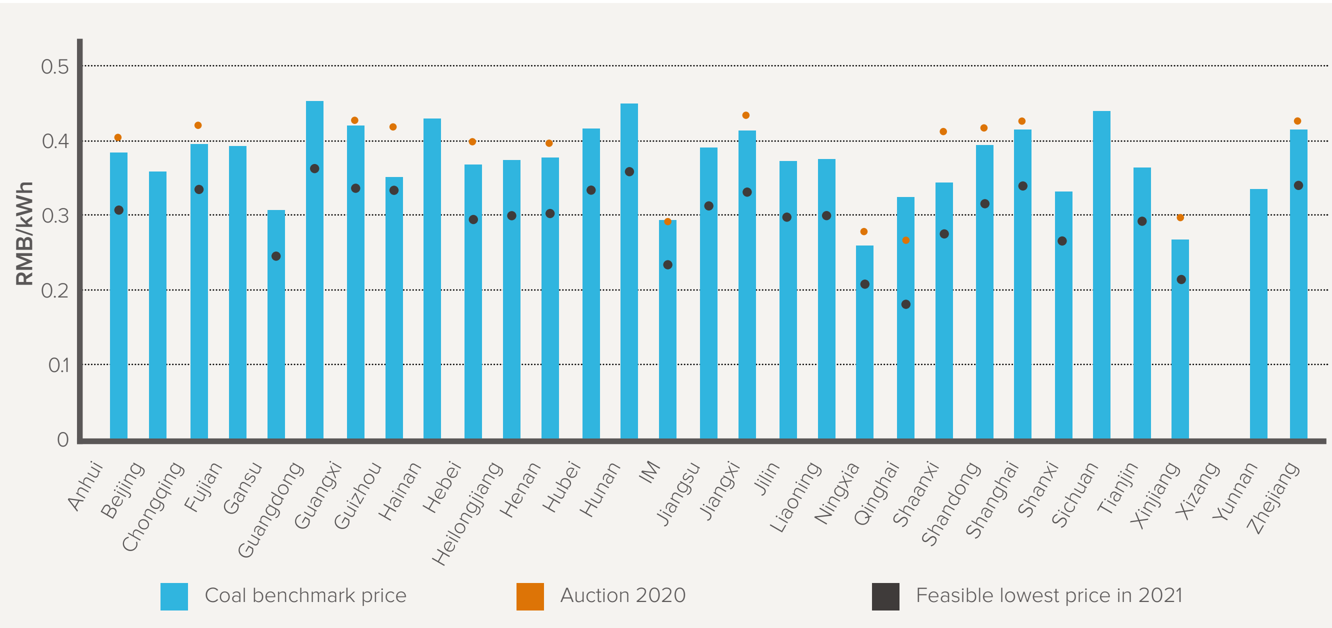
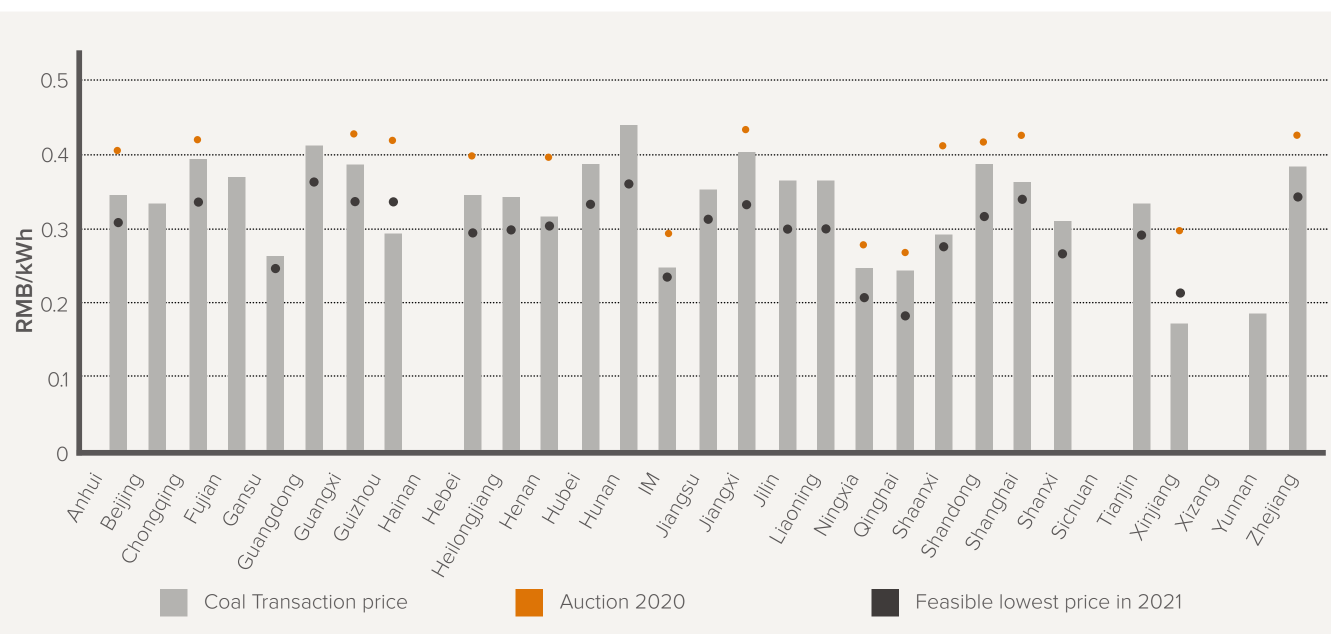


EXHIBIT 9

Comparison of Existing Coal, 2020 Solar Auctions, and Feasible 2021 Solar Prices in China[11]



[vii] 2021 attainable prices are calculated by applying 20% reduction rate on 2020 lowest permitted prices.

Onshore wind will soon be cheaper than coal, with offshore wind competitive by the late 2020s

For onshore wind, major changes in the policy framework have made it more difficult to discern the latest underlying cost trend. However, provided that future policy supports the strong volume growth required to meet the 2030 objective indicated in Exhibit 2, costs will almost certainly soon fall below new coal and below the coal transaction price later in the 2020s:

- Chinese onshore wind costs have declined about 40% since 2010 and BNEF estimates suggest a range of \$41/MWh–\$62/MWh in 2020, making it already highly competitive with new coal.

- This strong decline seemed to make it possible to remove wind subsidies before solar, with all wind subsidies due to end after 2021 (Exhibit 10).

- Auctions for wind were introduced in 2018, but many provinces decided to hold no auctions since many had already hit 13th Five-Year Plan targets for quantity of wind development. Auction results for the provinces which did hold auctions in 2019 (such as Tianjin and Chongqing) produced bids for subsidies in the \$10/MWh–\$20/MWh range, above the average \$9/MWh in the 2019 solar auctions.

- Newly permitted subsidy-free projects in 2020 have been a disappointingly small 11 GW.

This pattern of both quantity and price development reflects the fact that the declared end of the subsidy regime produced a surge of project construction and wind turbine orders which temporarily drove up costs and used up production capacity. But provided strong volume growth resumes, major cost reductions can be achieved. BNEF estimates that average costs could fall 30% to around \$35/MWh by 2025 and to \$30/MWh by 2030, with much lower costs in the most favored locations (Exhibit 11). A policy of clear medium-term quantitative targets, plus auctions to create cost reduction incentives, will maximise the cost reduction achieved.

Offshore wind developments in China have been limited to date, with only 6 GW of installed capacity by 2019. The current cost to build new offshore wind capacity is estimated to be significantly above new coal costs. With global costs falling rapidly and the Chinese industry rapidly developing, cost reductions could make offshore wind competitive with new coal beyond 2025. Clear quantitative targets, such as Guangdong's goal to build 30 GW of offshore wind by 2030, will help drive these cost reductions.[12]

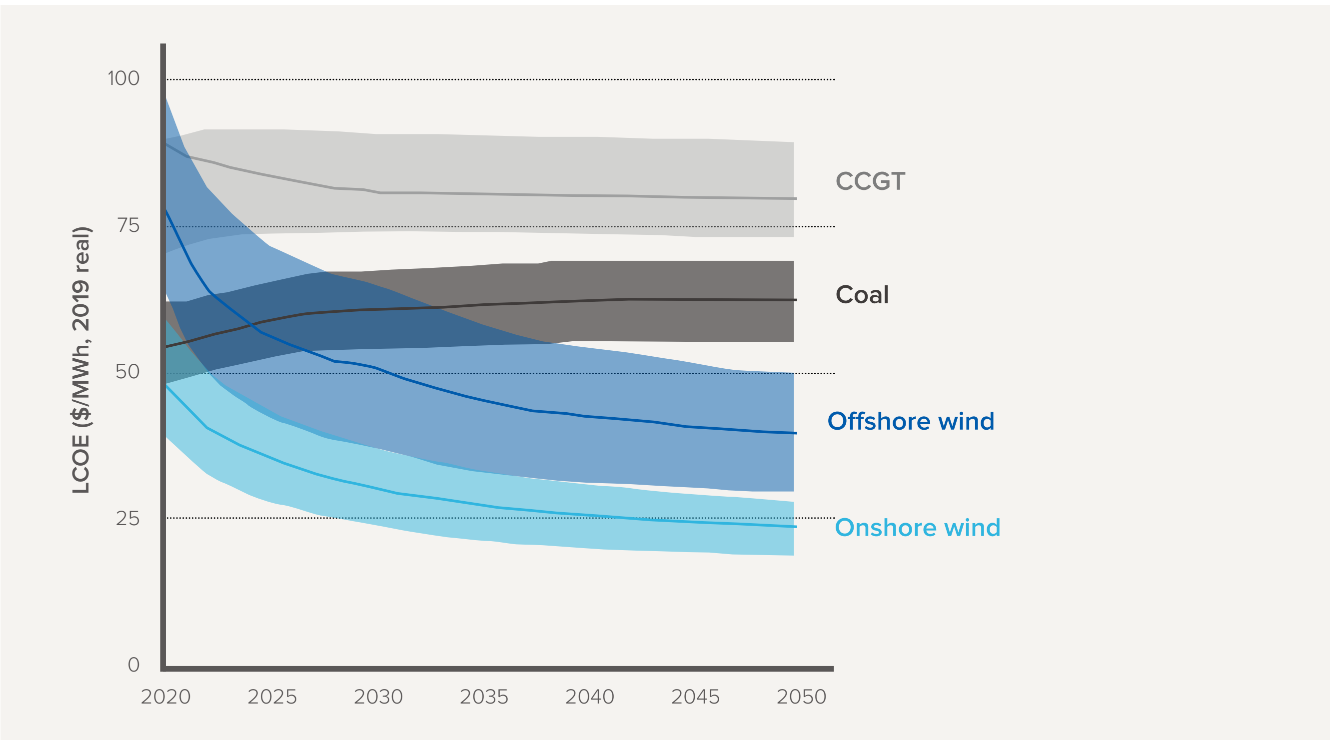
EXHIBIT 10

Renewables Subsidy Phase-Out Timeline

	COD deadline	
	Permitted before 2019 January	Permitted in 2019 and 2020
Onshore Wind	End of 2020	End of 2021
Solar	No clear deadline	

EXHIBIT 11

Economic Comparison of New-Build Bulk Generation in China



Source: BloombergNEF

Further cost declines threaten existing coal

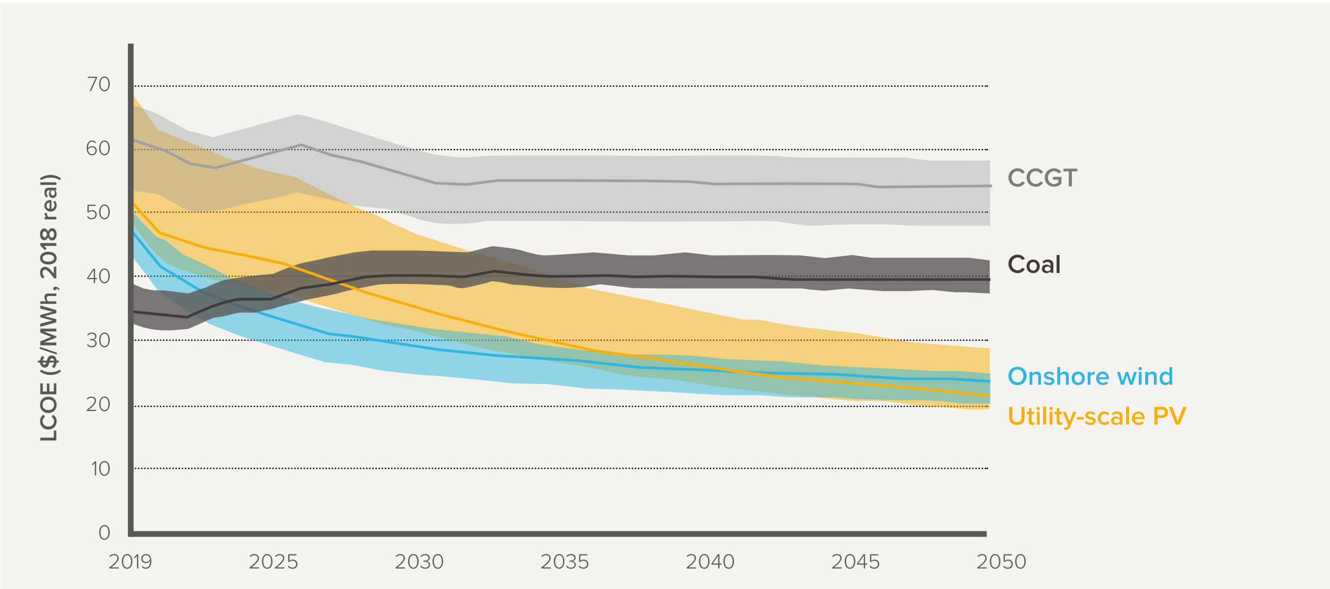
Solar and wind are already, or will very soon be, the cheapest sources of new electricity generation in China. In addition, by the late 2020s, BNEF estimates that new wind and solar developments will deliver electricity below the cost of many existing coal plants (or combined-cycle gas turbines), which can make existing coal assets uneconomic (Exhibit 12). This danger is exacerbated by the overcapacity of existing coal generation, which currently has an average capacity factor of 56%. Provinces in northwest and southwest China, where abundant renewable resources are available, are already facing this challenge. Coal plants are running at an average capacity of 35% in these regions, resulting in significant financial losses and stranding risks.

Nuclear and hydropower costs competitive

BNEF estimates suggest that Chinese nuclear power can deliver electricity at about $51/MWh–$68/MWh, and current prices confirm this level. This makes zero-carbon nuclear fully competitive with coal as a provider of baseload electricity. Chinese hydro plants also deliver zero-carbon electricity at costs competitive with coal. The transaction prices for hydro plants are often around $40/MWh, with some as low as $30/MWh, significantly below typical coal power transaction prices, reflecting very low marginal cost of running hydro plants. It is commonly acknowledged that hydro is the cheapest generation source in China.

EXHIBIT 12

LCOE of New PV and Onshore Wind versus Running Costs of Existing Coal and Gas in China



Source: BloombergNEF

POLICY SPECIFYING CLEAR DEPLOYMENT TARGETS CAN RESTORE THE PACE OF COST REDUCTION

China's past development of zero-carbon electricity has been very impressive: with over 400 GW of wind and solar capacity already in place, it leads the world in renewable deployment. This reflects the success of past policy, with initial subsidies and quantitative targets driving rapid industry expansion and resulting cost reduction. Certainty about the quantitative pace of expansion has enabled the industry to achieve the economy of scale and learning curve effects which have brought costs down to competitive levels, not only in China but also globally.

However, the current pace of zero-carbon power coming online is not on track to meet the levels needed by 2030, in particular the rate of wind deployment. As our scenario suggested, to achieve the levels required in 2030, China needs to add approximately 650 GW of solar PV, 600 GW of onshore wind, 60 GW of offshore wind, 110 GW of hydro, and 65 GW of nuclear power (Exhibit 2).

Solar project approvals in 2020 are running at 59 GW, the annual pace required to achieve the 2030 amount, with unsubsidised projects accounting for 33 GW. 65 GW of new nuclear looks feasible, given a pipeline of around 12 GW under construction and 22 GW in planning with defined construction start date. The addition of 110 GW of new hydro is backed by about 40 GW of projects under construction and over 20 GW in the planning stage. However, the pace of new wind development is off-track relative to 2030 levels. With wind subsidies phasing out, the 11 GW of approved unsubsidised wind is too slow to meet rising demand.

An annual investment pace of 55 GW of wind per year is undoubtedly achievable if appropriate policies are in place: in 2016 and 2017 over 30 GW was permitted in each year as wind capacity increases ran ahead of the 13th Five-Year Plan targets. And it is likely that the pace of project proposal and permitting may naturally increase somewhat over the next few years as wind developers and turbine manufacturers complete the backlog of existing projects and orders. But there is also a danger that the pace of investment will be too slow for several years, and that new coal investments will fill the gap, creating unnecessary cost and stranded assets later on.

The appropriate policy response is to create sufficient certainty about the quantity of wind (and solar) projects to ensure that the attainable cost and price reductions are achieved. Experience from other countries suggest that as solar and wind costs approach or fall below fossil fuel costs, removing the need for subsidies, it is still important to provide renewable developers with price certainty for a large share of their output. This reduces the risks of renewable development and as a result cuts costs and required prices.

This can be achieved either via regulatory targets for the percentage of power which must come from renewables (such as China's renewable portfolio standards) and/or via the continued use of auctions for predetermined quantities of renewable power, even if it is expected that these auctions will produce prices below the fossil fuel price.

In the UK, for instance, the Prime Minister has recently committed to build 40 GW of offshore wind projects by 2030,[viii] with auctions to ensure their delivery at least cost. These auctions will determine "contracts for difference" versus the wholesale power price. These may in some cases produce payments from the renewable energy developer to the grid—if the auction strike price is below future wholesale prices—but still offers conditions that are highly attractive to developers because they provide price certainty.

The specific policies required to drive rapid development are described in Section 5. Provided such policies are in place, renewables generation costs will continue to decline, delivering new supply at costs below new coal, and below the cost of many existing coal plants before 2030.

In China, as in many other markets around the world, the crucial question is no longer whether renewables and other zero-carbon generation are cost-competitive. Instead, the main areas of focus are around the technical and economic challenges of integrating a high share of VRE into the grid.

[viii] Since the Chinese power system is about 25 times larger than the UK system (measured by generation), this is roughly equivalent to a 1,000 GW target in China

3 TECHNICAL GRID MANAGEMENT CHALLENGES ARE SOLVABLE

TECHNICAL GRID MANAGEMENT CHALLENGES ARE SOLVABLE

In China, VRE currently accounts for 21% of installed capacity and 10.2% of power generation. This will continue to expand, and as Section 2 has shown, will deliver power generation at competitive costs. But many working in the Chinese power system continue to express concern that it may be technically impossible or prohibitively expensive to expand renewable shares significantly above the current level.

Such concerns were often heard in other power systems at a similar stage of VRE expansion. But across the world, many countries are already operating with shares of VRE, which on some days account for over 50% of total energy supply, with peak power percentages even higher.

In Germany, renewables generated 77% of net power supply in a single day on April 22, 2019, with wind generating 40%, solar 20%, and others 17%.[13] Across the European Union, renewables in total accounted for 54% of total electricity supply on May 11, 2020, and 55% on May 24, 2020.[14] In California, wind and solar power supplied 49% of total demand at a moment around 11:20 a.m. on March 23rd, 2017.[15] And in the UK, wind generation accounted for nearly 60% of total power supply at 1:30 a.m. on August 26, 2020.[16]

This makes it clear that it is technically possible to run power systems at far higher levels of VRE than in China today, and indeed far higher than the levels in Exhibit 2. This reflects the fact that there are clearly available solutions to the four categories of technical challenge often mentioned as VRE penetration rises:

- Frequency control
- Voltage control
- Fault ride through
- Capacity utilisation of long-distance high-voltage DC (HVDC) lines

FREQUENCY CONTROL

The biggest concern expressed by some Chinese industry experts is that rising VRE shares will make frequency control more difficult. But other countries have developed a range of solutions which allow stable system operation at very high VRE shares.

Stable system operation requires instantaneous supply/demand balance to maintain frequency within an acceptable range. If supply and demand are in significant imbalance, frequency deviations can cause generating units to trip off. In traditional power systems dominated by thermal generation, rotating inertia has provided a flexible means to help moderate frequency fluctuations, and dispatchable power supplies have provided additional generation output to meet load changes.

VRE by contrast is not dispatchable at will, and its future output cannot be predicted precisely. As a result, frequency control becomes more challenging under the existing system as VRE shares rise. But these challenges can be overcome by a combination of four means:

1. Improved forecasting of renewable output

The greater the uncertainty about future VRE output, the greater the need to maintain operating reserve and flexible capacity that can respond to unanticipated shortfalls or excesses. If forecasting accuracy can be improved, the need for "regulation capacity" (i.e., capacity that can ramp up and down) or operating reserves, can be constrained even as VRE shares increase.

In the case of CAISO for instance, VRE's generation share increased from 12.2% to 20.9% between 2015 and 2019,[17] but because mean absolute percentage error (MAPE) improved significantly, both on a day ahead and real-time basis, requirements for regulation capacity and operating reserve could be broadly unchanged (Exhibit 13).

China's MAPE is currently far higher than CAISO's—about 10%–20% versus 4%–6% at the day ahead timescale. Improved forecast accuracy should therefore be a high priority. Box A sets out key best practices.

EXHIBIT 13

Power System Operation Data Comparison between CAISO and China[ix]

		CAISO		China
Year		2015	2019	2019
Yearly electricity consumption (GWh)		231,495	214,955	7,225,000
VRE penetration		12.2%	20.9%	10.2%
Wind forecast MAPE	Day-ahead	6.2%	5%	~10%–20%
	Real-time	2.7%	1.1%	-
Solar forecast MAPE	Day-ahead	6.4%	4.2%	~10%–20%
	Real-time	3.7%	1.6%	-
Regulation requirements	Regulation up (MW)	347	~350	-
	Regulation down (MW)	327	~430	-
Operating reserve (MW)		1,664	~1,600	-

[ix] CAISO's data is summarised from resources in endnote 17.

Box A: Best practices in improving VRE forecast

A list of international practices for improving forecast accuracy and dispatch:

- **Improve the data quality.** Ensure checks and balances on the data quality going into the forecast models for the historical training sets as well as the information used to feed the forecast processes.

- **Keep updating the forecast algorithm and software.** Perform accuracy analysis on the forecasts provided and have regular feedback forums with the provider on what is being observed.

- **Evaluate the forecast and feedback for improvement.** Run multiple statistics on renewable accuracy to ensure that a full assessment of what is being observed in real-time operations is monitored and addressed through forecast improvements.

- **Reduce the key forecast timelines.** Work with external forecast providers on reducing the key forecast timelines.

2. Predict and reduce extreme short-term renewable ramping

Even if forecast accuracy is improved, sudden and unexpected weather changes can produce rapid VRE ramping, in particular from wind farms. The danger that this creates for frequently control can be offset by:

- Detection and prediction of large-scale ramping events: As one example, ERCOT has developed the ERCOT Large Ramp Alert System (ERLAS), which generates a probabilistic distribution of ramp events of different magnitudes and durations, providing 15-minute regional and system-wide forecasts for the next six hours. This is used to warn system operators of possible large and rapid changes in wind output.

- Reduce the extent of wind ramping: Wind turbine design and operations can be adjusted to prevent sudden increases or decreases in wind speeds turning into equally sudden increases in power output. Several operators therefore require windfarms to limit the maximum pace of up or down ramping (Exhibit 14).

EXHIBIT 14

Comparison of VRE Ramp Rate Limitations[18]

	Installed capacity of wind power	Ramp rate limitation
In ISO-NE (ISO-New England)	< 200 MW	< 20 MW/minute
	> 200 MW	< 10% of nameplate capacity per minute
SPP (Southwest Power Pool) in America	< 200 MW	< 8 MW/minute
	> 200 MW	< 4% of nameplate capacity per minute

3. Use VRE and other nonthermal plants to provide frequency control services

In many countries, including China, it has been a common requirement for VRE to provide primary frequency regulation. However, China still relies solely on thermal plants to provide secondary frequency regulation (also known as automatic generation control [AGC] service). In other countries, however, changes to inverter or management systems now enable VRE to provide AGC. In Colorado, utility Xcel Energy now requires wind turbines to be equipped with AGC capability, and two-thirds of the wind farms in its area of operation are already so equipped. Plant operators have also shown that solar photovoltaic plants can provide AGC by using smart inverters combined with advanced plant controls. This has been tested by the California Independent System Operator (CAISO) and proved feasible.[19]

Energy storage in flywheels and batteries can also provide frequency control services; indeed, their response to frequency control signals is 17 times faster than conventional thermal units. Use of batteries for frequency control is therefore now growing rapidly:

- In Australia battery storage now provides frequency control services at the 6-second, 60-second, and 300-second timescales. In two generator trip accidents in December 2017 and January 2018, rapid battery response reduced recovery time significantly.[20]

- In the United States, the Federal Electricity Regulatory Commission has since 2013 allowed batteries to connect to the grid to provide power supply resources as a small generator. By 2015, frequency regulation markets in the PJM, CAISO, NYISO, MISO, and ISONE regions were utilising battery storage.

In ERCOT, meanwhile, some industrial loads that meet specific requirements for interval metering and telemetry are allowed to provide frequency regulation services as controlled load resources.

4. Improving system inertia monitoring and delivering it in new ways

The more accurately that system inertia can be monitored and forecast the lower the need for inertia resource. ERCOT has therefore developed an Inertia Monitoring Tool which calculates the total inertia contribution of all online synchronous generators and forecasts the next seven days' inertia conditions on a rolling basis. System operators can then dispatch synchronous generation to increase inertia when needed, reducing the need to maintain more inertia than required.

In addition, system inertia can be provided by non-thermal resources such as:

- Synchronous condensers or synchronous compensators
- Energy storage with rotating masses, like flywheel storage
- CSP (concentrating solar power)[21]
- Retrofitted inverter-based generators (wind turbines, solar PV, and batteries)[22]
- Rotating machines on the demand side

VOLTAGE CONTROL

Voltage control is sometimes mentioned as a potential challenge as VRE shares rise, but technical solutions are clearly available. There are two issues that need to be addressed, reactive power and voltage harmonics:

- Reactive power must be compensated instantaneously and locally to maintain the power factor within the permitted range. Similar with other countries, the requirements of VRE on power factors is between -0.95 and +0.95. This can be achieved by deploying static var compensators (SVC), static var generators (SVG), static synchronous compensators (STATCOM), or thyristor controlled series capacitors (TCSC).

- Voltage needs to be kept within a safe range to ensure system stability. Harmonic waves are inevitable and would affect the voltage stability. Filters should be used to deal with the harmonic waves in voltage and improve power quality.

Voltage control devices should therefore be added to VRE power supplies and grid side. Provided this is done there will be abundant resources to provide voltage control, even under very high VRE scenarios.

EXHIBIT 15

Comparison of High Voltage Ride Through Requirements in Multiple Countries[23]

Country	High Voltage Ride Through (HVRT) requirements
US	Vmax=120% (of the nominal voltage) Tmax=1s
Germany	Vmax=120% Tmax=0.1s
Australia	Vmax=130% Tmax=0.06s
Spain	Vmax=130% Tmax=0.25s

* VRE should withstand faults and still connect to the system within the Tmax period when the voltage at the connection point increases to not higher than Vmax.

FAULT RIDE-THROUGH

Short-term voltage variations are common phenomena in power systems, and this variation can be amplified if the system suddenly loses a generator. It is therefore crucial for generation units to be equipped with the capacity to ride through the voltage turbulence before the system returns to normal. VRE units typically operate within a narrower acceptable voltage range than traditional thermal units, and may therefore be more susceptible to trip off, further enlarging the voltage variation and causing cascading failure.

This danger can however be offset by requiring VRE to be equipped with high voltage ride through (HVRT) capability. For already-existing plants this can be achieved by retrofitting the inverters. Most advanced countries therefore now impose an HVRT requirement within their grid code. Exhibit 16 shows examples.

In China, system reliability has been significantly improved by imposing a low voltage ride through (LVRT) retrofit requirement since 2012, and an adequately strong HVRT standard has been defined. But this HVRT standard is not yet mandatory for already-existing VRE plants.

Retrofitting existing plants to meet HVRT standards, as well as imposing those standards on all future VRE plants, should therefore be a priority.

HVDC CAPACITY UTILISATION

China has abundant solar and wind resources, but some of these are located at significant distance from major sources of electricity demand. High-voltage (HV) and ultra-high-voltage (UHV) lines enable long-distance transmission of renewable electricity to load centres, and HVDC is a more cost-effective technology over very long distances. HVDC lines are therefore being deployed extensively in China, playing a key role in support of the development of remotely located VRE.

Fluctuating VRE cannot by itself ensure high and steady utilisation of HVDC line capacity, and in some cases, there has therefore been pressure to build thermal plants alongside renewables, so that thermal capacity can "fill the line" when VRE supplies are low.

However, the technical and economic case for such thermal plants is far less convincing than often assumed, and will decline over time as other options become available:

- There is no need for an HVDC line to run at a steady rate, and while the dominant form of HVDC currently deployed in China—LCC-HVDC (line-commuted converter-based HVDC)—must run above a technical minimum utilisation rate, that rate is only 10% of nameplate capacity. There is therefore no technical need for thermal capacity to "fill the line" above this low level. Lower than 100% utilisation will obviously increase transmission costs per kilowatt-hour carried, but highly favourable VRE generation costs in remote locations can still make their development economic even if HVDC lines are not fully utilised.

- In addition, optimal combinations of wind and solar can increase average utilisation rates, and over time energy storage costs (e.g., in batteries or hydrogen) will create alternative ways to smooth and increase average line utilisation rates. Therefore, while there can be a useful role for already-existing thermal capacity to keep utilisation rates above 10%, there is no need to match large-scale VRE investment with new coal investment.

- The technical challenge of "commutation failure" can also be manageable in a VRE-dominated system. This failure can arise when disturbances produce an increase in DC currents and temporary interruption of power transmission. At present, thermal power is used to provide regulation and inertia to the system to reduce the impact of transient transmission loss during any commutation failure. But the same set of tools that can manage frequency and voltage variation in a high VRE system (e.g., synchronous condensers, battery storage, non-thermal sources of inertia, reactive power compensators, etc.) can also offset the impact from commutation failure.

- In addition, a new generation of VSC-HVDC (voltage sourced converter HVDC) is now able to deliver excellent voltage control capacity, eliminating the commutation risk, and simplifying technical requirements for both sending and receiving provinces. This comes with an economic penalty of reduced capacity but will still leave remote VRE generation and HVDC transmission economic in many locations, particularly in cases where already-existing lines can be retrofitted with VSC-HVDC capability.

Overall, all the technical challenges of HVDC can be solved without any new coal capacity to match VRE investment.

In summary, provided China implements required policies allowing the deployment of innovative solutions, there are no technical grid management issues that will prevent the growth of VRE to shares far above current levels. The remaining issue is how to balance energy supply and demand hour-by-hour across the day and day-by-day across the year in a system with a high percentage of VRE. The next section addresses that issue.

4 BALANCING SUPPLY AND DEMAND BY HOUR, DAY, AND SEASON

BALANCING SUPPLY AND DEMAND BY HOUR, DAY, AND SEASON

VRE generates electricity when the sun shines and the wind blows, which does not always match the load profile of when electricity is consumed. This creates a greater challenge in balancing supply against demand than in a system where the vast majority of power supply is dispatchable thermal or hydropower.

But across the world, several countries/regions already have VRE shares higher than Exhibit 2 illustrates for China in 2030. Germany, for instance, already has a 33% share and Spain has a 37% share—versus China's potential 28% share in 2030. Many countries plan to increase the share of zero-carbon power in total annual generation, primarily via VRE expansion, to at least 50% and in some cases more than 70% by 2030. Many of these nations also plan to increase total zero-carbon shares close to 100% in the following 10–20 years, with VRE accounting for as much as 80% (Exhibit 16).

This chapter sets out the lessons from this global experience and explains how these apply in China's specific circumstances. The clear conclusion is that China could easily integrate the 28% of VRE generation shown in Exhibit 2, and that future total system costs for an eventually zero-carbon system will be no higher and possibly lower than for today's fossil fuel-based system.

THE GLOBAL EXPERIENCE

The plans shown in Exhibit 16 reflect confidence that there are technically and economically feasible solutions to the flexibility challenge in relation to both daily and seasonal fluctuations of supply and demand. For renewable penetrations up to the levels typically seen today (e.g., 20% to 30%), the solution can in almost all cases be provided via flexible use of existing thermal capacity, whether gas or coal. As shares grow to much higher levels, a wider range of options will be needed and/or will be cheaper, but there is no doubt that they will be available.

EXHIBIT 16

Comparison of Zero-Carbon Power Generation Targets as a Share of Total by Country/Region

Country	VRE generation in 2019	VRE capacity in 2019	Target
Germany	33%	53%	65% renewable generation (including hydro) by 2030
UK	23%	36%	50% renewable generation (including hydro) by 2030
California	21%	23%	33% of retail sales of electricity in California come from eligible renewable resources by 2020, 60% by 2030, and 100% zero-carbon electricity by 2045
Spain	37%	49%	74% renewable generation (including hydro) by 2030
Sweden	10%	17%	100% renewable generation (including hydro) by 2040
China	8.6%	20.6%	50% non-fossil generation by 2030[24]

Daily demand/supply balance

In most countries demand for electricity peaks during the middle of the day/early afternoon due to high demand in factories and offices, declining to overnight lows in the early hours of the morning. Even before the growth of renewables, systems have therefore had to respond flexibly to this changing demand, primarily through variation in the output of coal or gas plants.

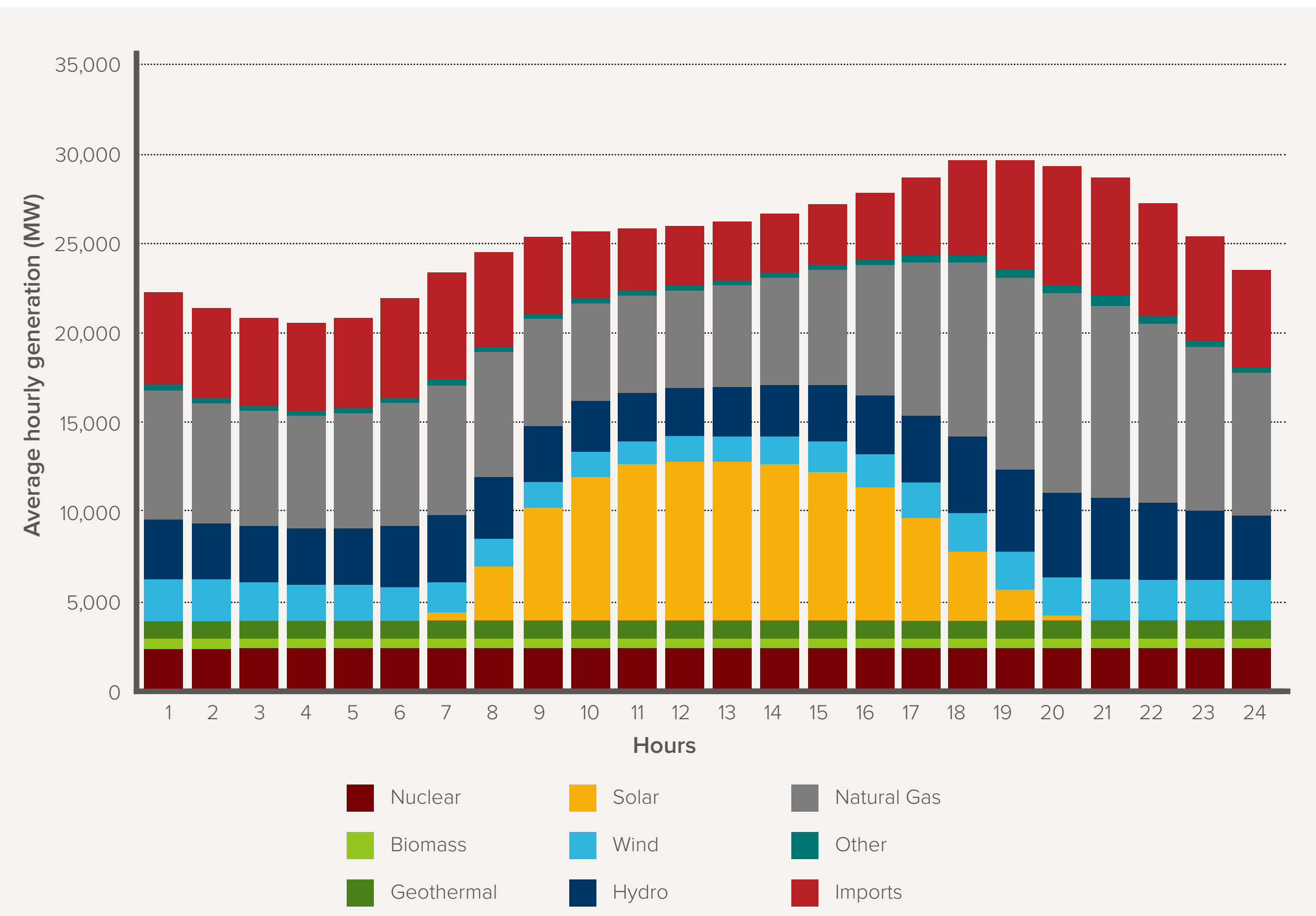
In one way the growth of renewables has tended to reduce the daily flexibility challenge, since solar output is higher during the day, coinciding with high demand.

But systems with large shares of solar supply tend to face a sudden increase in the demand for non-solar sources in the late afternoon/early evening, as solar supply rapidly falls but demand falls more slowly.

Daily wind supply profiles are more variable with specific local weather conditions; in some but not all regions wind energy supply tends to be higher at night. And in some regions (which face alternating cyclonic and anticyclonic weather systems) the day-by-day and week-by-week pattern of supply is more variable than for solar.

EXHIBIT 17

Average Hourly Generation by Fuel Type in California, 2019[25]



Source: CAISO

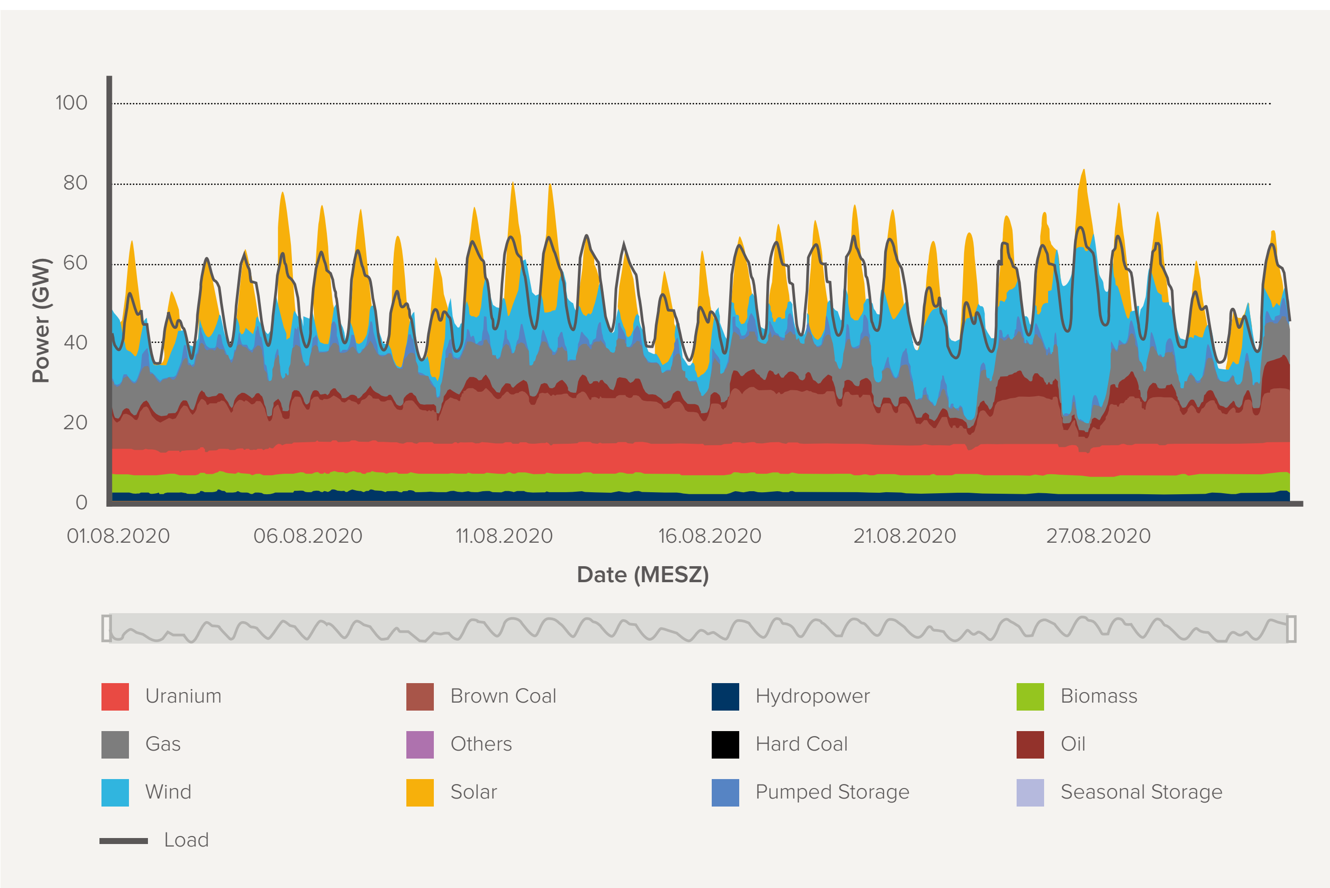
At the levels of renewable penetration seen so far, these daily flexibility challenges have proved easy to meet through a more flexible use of gas or coal plants. In California, gas generation varies through the typical day to balance the solar profile, with a rapid ramp up in the early evening and peak supply gas supply at around 7 p.m. to 9 p.m. (Exhibit 17).

In Germany, the flexibility need is met by variation in gas, hard coal and brown coal (lignite) generation, as well as by importing and exporting power. While gas is the most flexible—varying in week shown in Exhibit 19 from a minimum of 1.6 GW to a max of 9.9 GW (a variation equal to 84% of peak capacity use), hard coal also varied from 1.4 to 6.5 GW (a 79% variation). Even brown coal output varied from 3.5 to 12.0 GW (a 71% variation) (Exhibit 18).

As renewables penetration increases, the need for flexibility will increase. In countries with large gas turbine capacities it will remain possible to meet even greatly increased flexibility requirements with gas peaking plants which run for only a small number of hours per year. But other flexibility options are likely to play a growing and, in some cases, more cost-effective role. In particular for daily balancing:

EXHIBIT 18

Electricity Supply and Demand in Germany in August, 2020[26]



Source: Fraunhofer ISE

- Pumped hydro storage is likely to play a significant and increasing role. As Exhibit 18 shows, Germany already uses pumped hydro to a small extent to meet rapidly rising demand in the morning ahead of the solar supply surge, and in the late afternoon to offset the rapid solar decline.

- Dramatic falls in battery prices (down 85% in the past 10 years) have made battery storage an increasingly economic option, with several US utilities cancelling contracts for gas peaker plants in favour of renewable plus battery contracts. Given further cost declines (Exhibit 19), battery use will almost certainly gradually expand throughout the 2020s and grow rapidly thereafter as VRE shares begin to reach very high levels.

- Demand management also has huge potential to balance short-term shifts in VRE supply and electricity demand. If well deployed, this could be a significantly cheaper source of flexibility than other options. At the daily duration there are three major sets of opportunities:

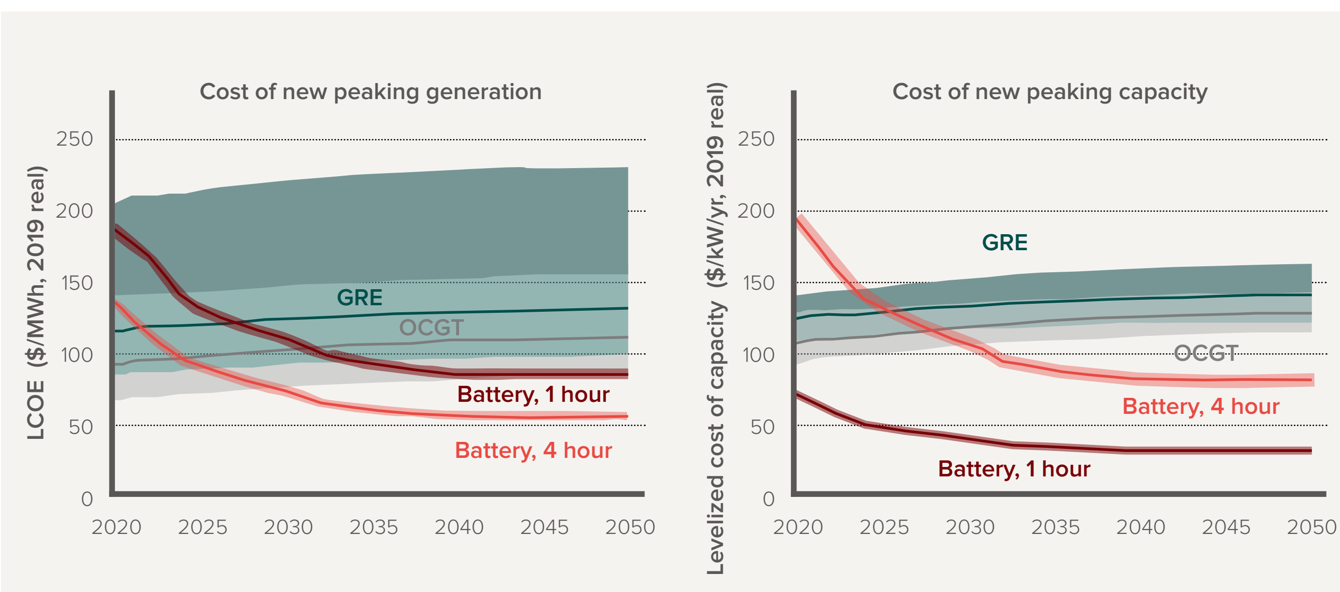
  - Electrified residential heat demand can be shifted, made possible either via high insulation standards or via small-scale heat storage technologies.

  - The time of day of EV charging can be shifted and EV batteries can be used as a grid storage resource via vehicle-to-grid discharge. The long-term potential here is huge. If by 2050 there are 1.5 billion electric cars on the world's roads, each with a 50 kilowatt-hour (kWh) battery, that will provide 75 TWh of potential storage capacity. This would be equal to 30% of the expected global daily electricity use, even in a world where annual electricity consumption had increased from today's 27,000 TWh to 90,000 TWh.[27]

  - In addition, opportunities for flexible industrial demand response are likely to grow. There is

EXHIBIT 19

Cost Comparison of Peak Generation in the United States, 2020



Source: BloombergNEF

the potential to vary loads on minute-by-minute, hour-by-hour, and day-by-day cycles in a wide and growing range of applications including retailer chilling systems, controlled environment farming, aluminium electrolysis, and hydrogen production via water electrolysis.

The key development needed to unleash these opportunities is more widespread adoption of time-of-day electricity pricing. Given these multiple options there is increasing confidence that the challenges of balancing daily supply and demand will be easily and cheaply manageable even as VRE percentages go far above 50% and eventually reach 80% or more.

Seasonal demand/supply balance

Seasonal balance refers to the need to balance supply and demand over multiweek or monthly time periods. It is useful to distinguish two subcategories.

- **Predictable long-term imbalances,** deriving from major differences in demand between seasons if these are not matched by differences in supply. In the future UK system, for instance, electrification of residential heat is likely to produce winter demand peaks as much as 80% percent higher than summer levels. In the UK's case this will be fortunately matched by the fact that wind supply (the UK's most abundant renewable resource) will also be far greater in winter. But in other countries there may be higher winter demand, but lower solar yield insufficiently offset by increased wind supply.

- **Less predictable weekly variations.** Even where there is a fortunate coincidence of average seasonal demand and supply peaks, there can be major weekly supply variations caused by weather cycles. The UK's greatest future balance challenge will arise when usually plentiful winter wind supply collapses for a number of days (or in extreme cases several weeks) as result of anticyclonic conditions over north-west Europe.

As VRE penetration reaches the sort of level envisaged in Exhibit 2, either of these seasonal challenges can be easily met through flexible use of existing thermal plants. Indeed, at low to moderate levels of VRE penetration, the seasonal challenge is often easier to manage than the daily, since it does not create the need for the rapid late afternoon ramping created by even moderate levels of solar supply. Varying coal plant utilisation rates between different seasons, months, or weeks, or closing down some plants entirely for some weeks, places less demand on thermal flexibility than rapid day-by-day variation.

In the longer term, however, and as VRE penetrations reach levels far higher than the 28% envisaged in Exhibit 2, the seasonal balancing challenge becomes more difficult and expensive to meet. However, these long-term challenges will become manageable with cost-effective solutions long before systems reach such high levels of renewable penetration. There are multiple options:

- It is possible to meet seasonal peaks with thermal plants inherited from the fossil fuel-based systems, which run only a small percentage of total annual hours. This can be economic if electricity prices are higher at peak times, or if plants are remunerated to provide capacity. To achieve a completely zero-carbon system, they will need to eventually be fitted with carbon capture and storage.

- Gas turbines can be converted to burn hydrogen (or new investment can be made in such turbines) with the hydrogen produced by electrolysis when renewable supply is in excess of demand and power prices are therefore low.

- Pumped hydro capacity can be used to meet intermediate duration flexibility requirements (e.g., one- to three-day supply deficits).

- Seasonal/weekly demand management can be implemented. Unlike daily demand management, this would not be focused on the potential to time-shift residential heat demand or EV charging, but on the potential for some industrial activities to plan maintenance shutdowns. It can also be used to vary capacity utilisation in response to predictable seasonal fluctuations in the energy supply/demand balance and thus prices.

Global estimates of total system cost

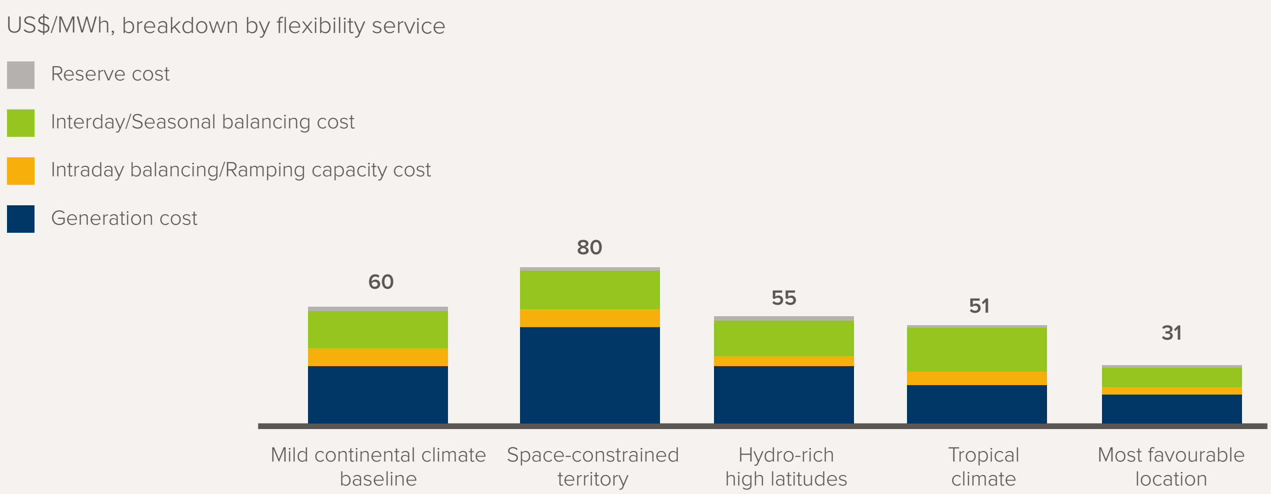
Implementing the flexibility options described above will in some cases add to the total cost of system operation. However, this additional cost is offset by the lower cost of zero-carbon generation described in Section 2. As a result, it will be possible by the mid-2030s to build systems that rely on variable renewables for as much as 85% of all electricity supply, and to do so with total system costs, which are as low (and in some cases lower) than fossil fuel-based systems today.

The precise picture will differ significantly by location, given major differences in renewable resources. Estimates by the ETC shown on Exhibit 20 suggest that future total costs in most systems will fall within a \$51/MWh–\$60/MWh range. But higher generation costs in some space-constrained countries could push total costs up to \$80. Meanwhile, in the most favourable locations, with abundant wind and solar resources, low generation costs and more limited seasonal flexibility needs could produce total costs as low as \$31/MWh. In most countries these costs will be lower than those for a system which continues to rely primarily on coal or gas.

Countries can therefore commit to a rapid increase in renewable and other zero-carbon penetration, confident that the long-term total system cost impact will be at most a trivial increase and potentially a significant reduction.

EXHIBIT 20

Global All-in System Cost in a Near-Total-Variable-Renewable Power System by 2035



All archetypes are based on same power demand and have identical reserves costs

	Mild continental climate baseline	Space-constrained territory	Hydro-rich high latitudes	Tropical climate	Most favourable location
Seasonal needs	Strong winter peak Long winter	Identical to baseline	-5% vs. baseline Generation capacity partially covered by existing hydro	-25% vs. baseline Limited seasonality (low latitudes)	-50% vs. baseline Limited seasonality (low latitudes)
Daily needs	Medium: heating needs but complementary wind and sun	Identical to baseline	-41% vs. baseline 80% covered by cheap existing hydro	+20% vs. baseline Long periods with no sun/ wind + high air conditioning	-50% vs. baseline Low: mild evenings
Bulk RE generation	Complementary wind and solar	+67% vs. baseline Space availability challenge	Identical to baseline	-33% vs. baseline Abundant wind and solar	-50% vs. baseline Very abundant wind and solar

Source: Climate Policy Initiative and Energy Transitions Commission

CHINA-SPECIFIC CHALLENGES AND SOLUTIONS

Within the global picture described above, the challenge facing any specific country reflects its distinctive supply and demand characteristics. In China's case, there is nothing about the pattern of demand that creates any distinctive challenge. However, two features of China's electricity supply—its starting point of reliance on coal rather than gas, and the less flexible nature of its hydro resource—create distinctive but manageable problems.

As other countries have done, China could easily integrate the 28% VRE shown on Exhibit 2, and does not need to build any new coal power stations: and in China as elsewhere, the long-term total system cost of a fully decarbonised system with VRE percentages far above 50%, is likely to be below the current cost of China's fossil-dominated system

China's demand profile now and in 2030

Neither daily nor seasonal conditions make balancing supply and demand more difficult in China than in other countries that already have renewable VRE equal to 20% to 35% of the total.

Exhibit 21 sets out typical daily load profiles for Gansu, Zhejiang, and Guangdong provinces. In the case of Gansu, the very large share of demand that comes with industry (78%) results in a fairly flat, low profile. However, the profiles for Zhejiang and Guangdong, which have higher shares of commercial office and residential demand, are broadly similar to patterns seen elsewhere (see Exhibits 18 and 19 above). Demand is typically lowest in the middle of the night, ramps up rapidly around 7:00 a.m. – 10:00 a.m., and declines rapidly in late afternoon.

Even in these provinces, however, total max load to min load ratios are less than seen in some developed economies. For instance, in the UK the typical daily maximum to minimum load ratio is around 1.71 in both winters and summers, compared with the ratio of 1.57 for Guangdong and 1.5 for Zhejiang on the typical days illustrated.

Seasonal demand patterns also vary significantly between China's provinces (Exhibit 22). In a typical northern province, the seasonal variation is fairly limited. But southern provinces typically have a significant summer peak driven by AC demand, and central and eastern provinces often have both a summer AC and a winter heating peak. In the southern province the scale of variation, with the peak summer month about 30% above the typical winter average, is similar to that seen in California (Exhibit 23). But the eastern and central provinces variation is a bit larger.

At the national level, China's large continental scale and combination of different climatic zones smooth out some of the variations seen at the provincial level to produce the national seasonal pattern illustrated in Exhibit 24, with the national peak in August about 30% above the national troughs in May and October.

In China as elsewhere, demand patterns will change over time as new forms of electricity demand grow in relative importance. Forecasts of demand growth to 2030 show a rising share of commercial and residential building demand (driven by heating, AC, and computer equipment) and this is likely to somewhat increase the variability of demand by day and season. But some countries that are planning for more rapid progress to very high VRE shares, also face more dramatic increases in seasonality. In the UK for instance, which plans to electrify a large share of residential heat but which only has limited summer AC demand, the ratio of average winter day demand to average summer day demand, which today is about 1.5:1, could increase to 1.7:1 by 2050.

In summary, China's demand profile does not create a distinctively difficult balancing challenge.

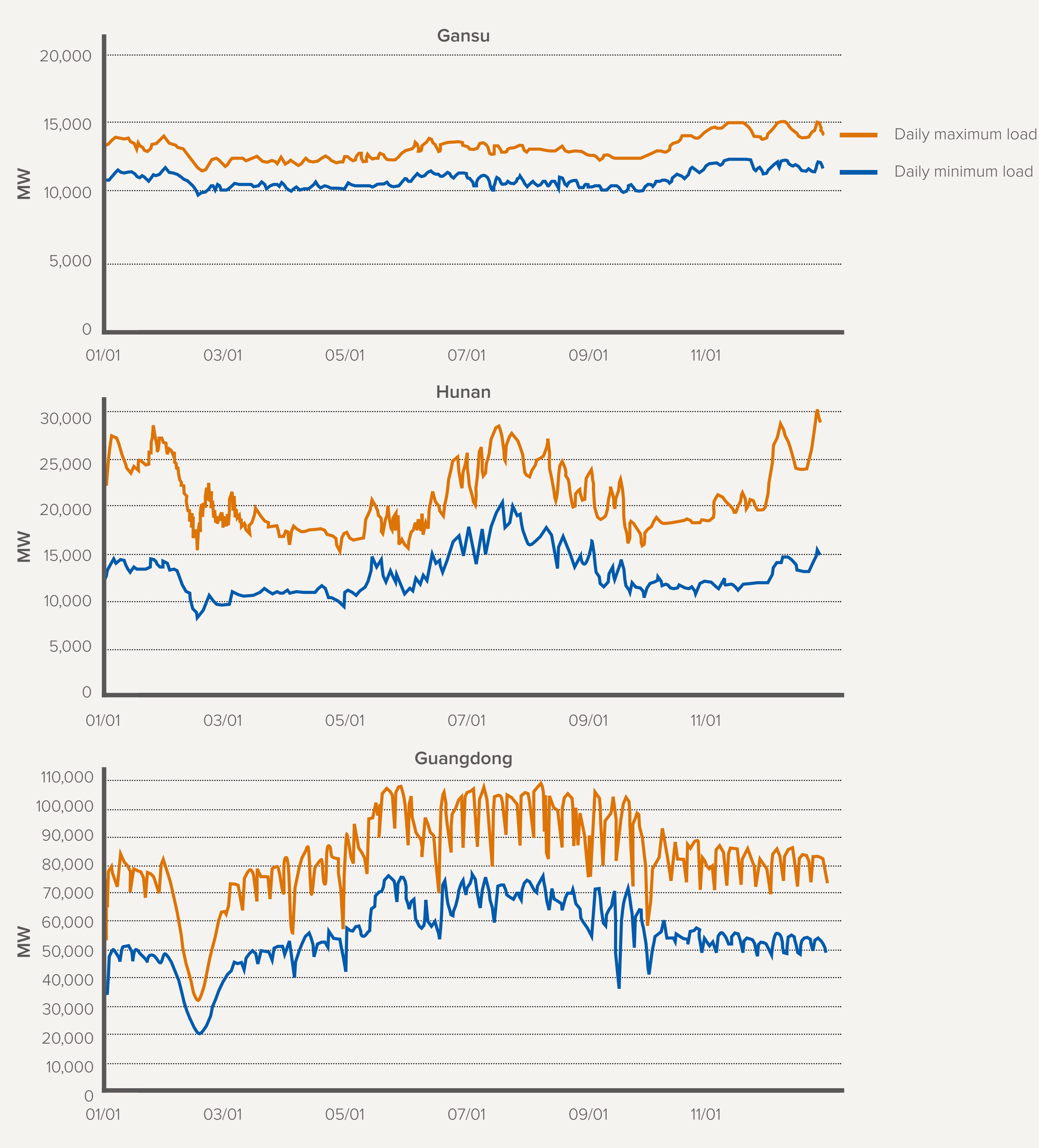
EXHIBIT 21

Typical Daily Load Profiles in Three Chinese Provinces, 2019[28]

Source: National Energy Administration

EXHIBIT 22

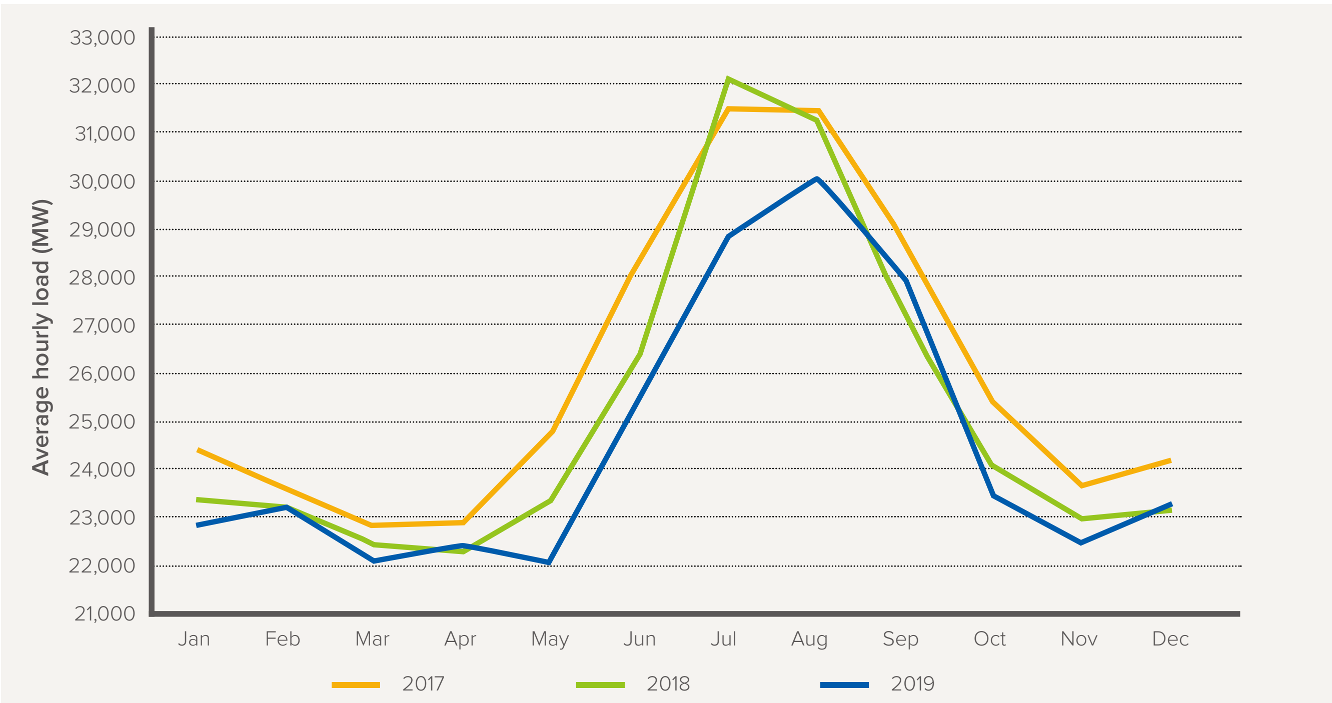
Typical Yearly Load Profiles in Three Chinese Provinces, 2019



Source: National Energy Administration

EXHIBIT 23

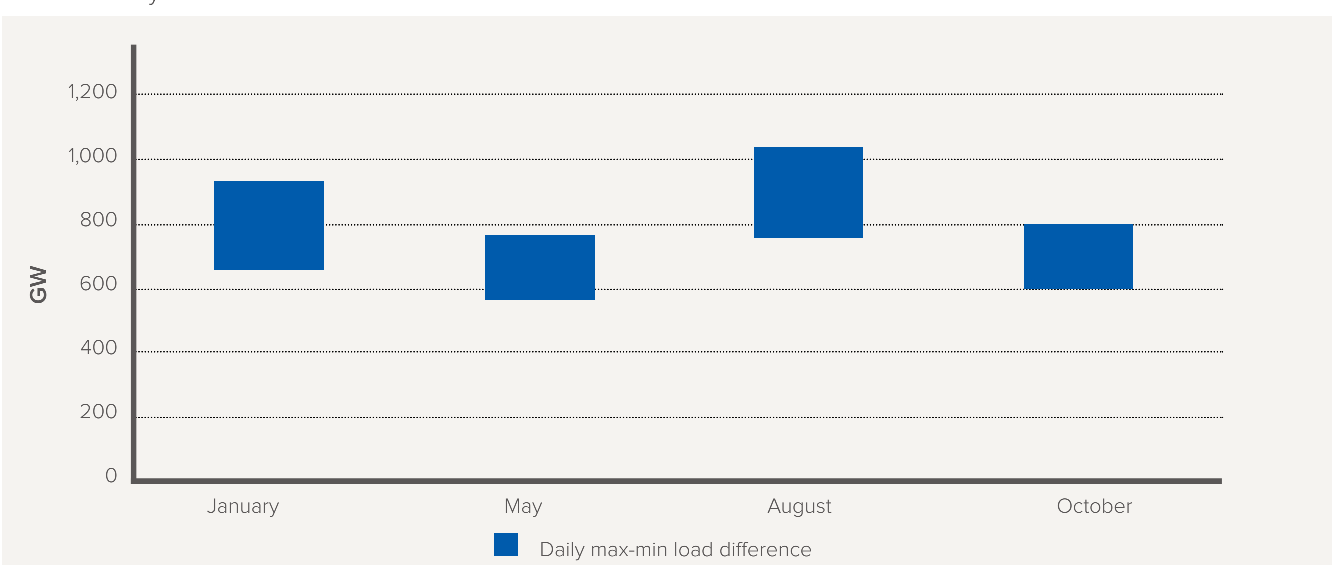
California Average Hourly Power Load by Month[x]



Source: CAISO

EXHIBIT 24

National Daily Max and Min Load in Different Seasons in China



[x] The 2017 line is more representative of underlying demand than 2019, since the spread of residential "behind the meter" solar is gradually removing demand from the grid.

CHINA SUPPLY FLEXIBILITY: TWO IMPORTANT FEATURES

On the supply side, China has two distinctive features that will make the integration of VRE more challenging than in some other countries:

- **Current heavy reliance on coal,** which today accounts for about 62% of China's power supply. As described above, thermal flexibility has been the key mechanism by which countries have balanced supply and demand in the early stages of transition to high VRE shares. And since gas is inherently more flexible than coal, countries that start with large gas shares (e.g., California 42.97% or UK 39.65% of total generation in 2019[29]) face an easier challenge than those that start with coal-dominated systems. But the challenge can certainly still be met. As Exhibit 18 shows, coal plant flexibility plays a major role in Germany, and countries currently relying on gas flexibility are planning to dramatically reduce or entirely eliminate its role within the system by 2050. However, a large initial reliance on coal makes it important to optimize and utilize the flexibility of existing coal, especially the CHP plants.[xi]

- **China's hydro resources are less flexible.** In many regions/countries (e.g., Scandinavia, Switzerland, and Austria) hydro is seen as the most flexible resource, which can meet both daily and seasonal flexibility needs. However, China's hydro is currently playing a much less flexible role within the system. This reflects a combination of physical and contractual factors.

  Some of China's hydro resources are inherently less flexible than those of other countries—with more run-of-river hydro and fewer dams, lower reservoir capacity, and lower height drops. Also, to a far greater extent than in Europe, China's dam system also serves flood control, shipping, and irrigation needs. There is a large inherent supply variation between winter and summer as a result of rainfall patterns. However, there are more easily fixable contractual rigidities, with some hydro supplied on an inflexible basis even when it could easily meet flexibility needs.

Despite these complexities, there is no doubt that China could meet the challenge of integrating the 28% of VRE by 2030 shown in Exhibit 2 and much higher levels in subsequent years. To do this cost-efficiently China needs to increase the flexibility of its coal and hydro resources, and address challenges created by the decentralised nature of China's grid management system and the provincial incentives that this creates.

Demand/Supply Balance at the National Level

If the Chinese power system could operate as one integrated national system, with complete interconnection between provinces, it would be easy to meet the challenge of integrating the 28% share of VRE illustrated in Exhibit 2.

Exhibit 25 sets out reasonable estimates of typical summer and winter day national demand profiles in 2030, together with a profile of wind and solar energy production compatible with the capacity shown on Exhibit 2, and with typical daily resource variation. Nuclear is shown as a totally fixed energy supply, and hydro is also shown with the unrealistically conservative assumption that it will be completely inflexible on an hour-by-hour basis. The implied need for thermal power is given by the space between the zero-carbon supply curve and the total load curve.

[xi] Most thermal plants in north China are CHP plants, which are pretty inflexible in winter in order to meet the heat demand.

EXHIBIT 25

Simulated National Daily Balance in Typical Winter and Summer Days in 2030[xii]

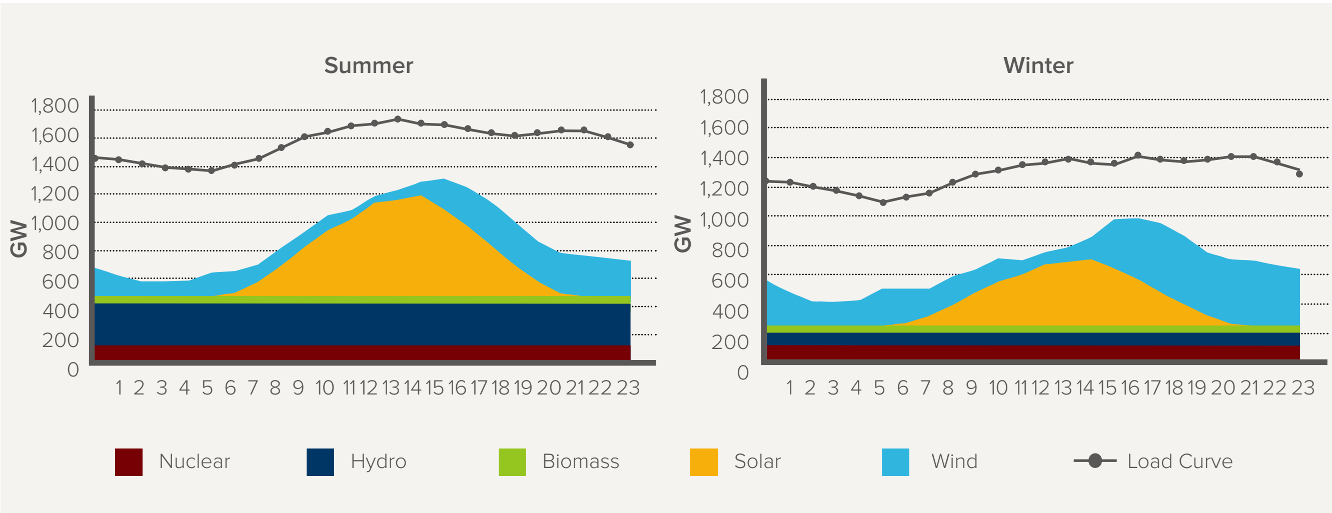


Exhibit 26 shows how thermal supply would have to vary over the summer and winter days, with peak thermal production during the late evening and middle of the night, and a significant trough in the mid-afternoon. The variation could be reduced by using pumped hydro as a daily balancing resource, and the exhibit illustrates the potential impact of the 81 GW of pumped storage now in place, under construction, or planned.

The resulting need for thermal supply could be partially met by highly flexible gas generation, which could meet evening and overnight peaks, and shut down completely in the mid-afternoon. This leaves a requirement for variation in coal supply which is clearly manageable even within existing levels of coal plant flexibility:

- The load variation hour by hour during the day is minimal, and even the seasonal variation amounts to less than 20% of total capacity, well below the 40% to 50% variation that plants can achieve even without shut down
- The maximum required ramp rate of 1 GW per minute in the early evening is far less than the 1% to 2% of nameplate capacity per minute that is already available

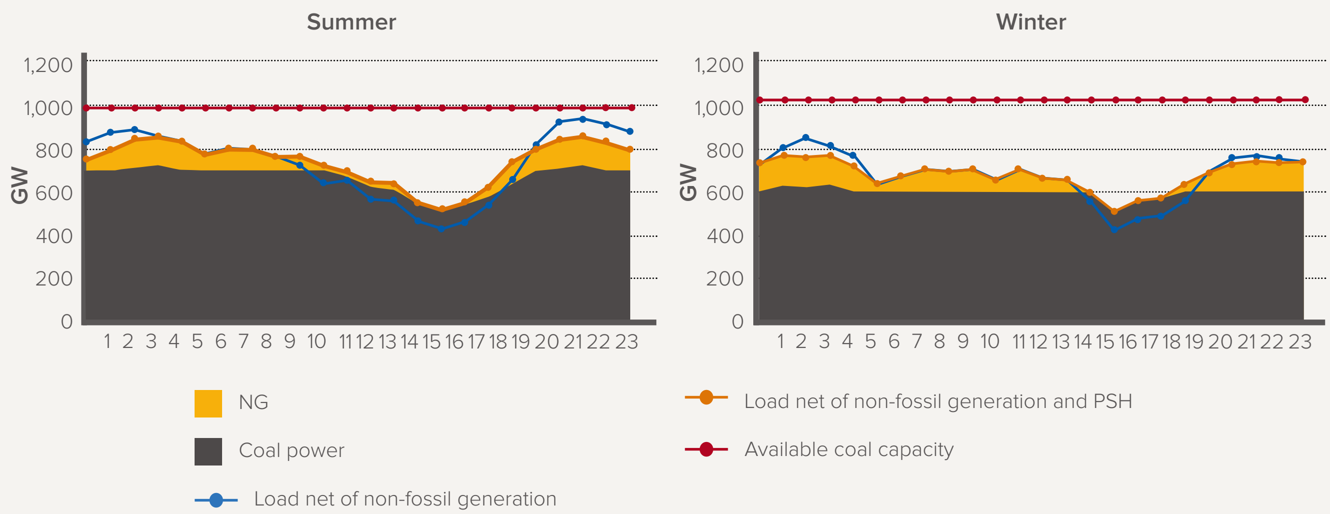
In real-world operation, random variations in wind and solar supply (even when averaged across the whole of China's landmass) would add significantly to short-term flexibility requirements. However, hydro supply could be varied significantly on an hour-by-hour basis, even if there are limits to significant variation over a longer time period.

Viewed from the point of view of a theoretical "one China" system, the challenge of balancing supply and demand in the face of a 28% VRE share can therefore be easily managed without major improvements in coal or hydro flexibility.

[xii] The load profile and renewable profile are based on Reinventing Fire: China's model assumption.

EXHIBIT 26

Estimated Flexibility of China's Coal Fleets, 2030



Provincial-Level Complexities and Challenges

The theoretical national-level analysis presented above provides a useful and informative context; but in reality, China's power system is today managed in a decentralised fashion with provinces as the key unit. Regional coordination makes possible some short-term adjustment of power excess or shortage between provinces within the same region, but daily dispatch decisions are primarily made at the provincial level, and nationally coordinated interprovincial export/import contracts are set on an annual basis and treated as fixed on a day-by-day basis. This decentralised approach increases the danger that flexibility resources will be insufficient to deal with a rising VRE share.

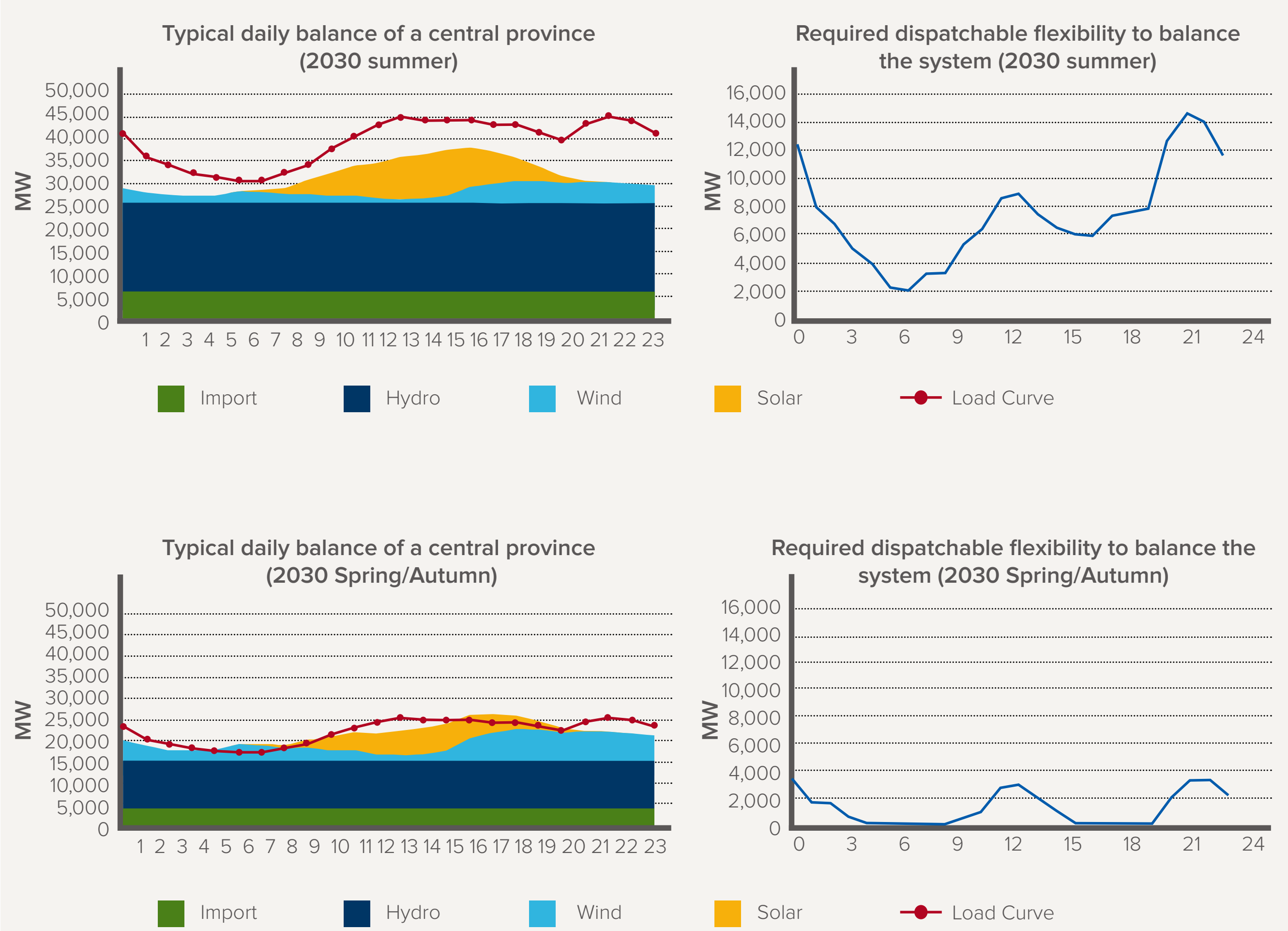
This is illustrated in Exhibits 27 and 28. These show the flexibility challenges facing a typical energy-importing and typical energy-exporting province in 2030 under the same extreme assumptions as before: that hydro resources are fixed, and both import and export contracts are wholly inflexible.

- In the case of the importing province (Exhibit 27) the growth of solar demand usefully reduces the need for peak thermal capacity in the middle of the day, but inflexible imports and hydro supply at night would require more variation in thermal supply than possible with current coal plants. Meanwhile, in spring and autumn, total inflexibility of imports and hydro would require that thermal plants close down entirely for some periods of the day.

- In the case of the exporting province (Exhibit 28), an inflexible export contract would make it impossible to export midday solar output (resulting in wasteful curtailment). Meanwhile, high evening wind supply would necessitate total thermal shutdown, which is uneconomic on a daily cycle basis as opposed to a longer seasonal cycle.

EXHIBIT 27

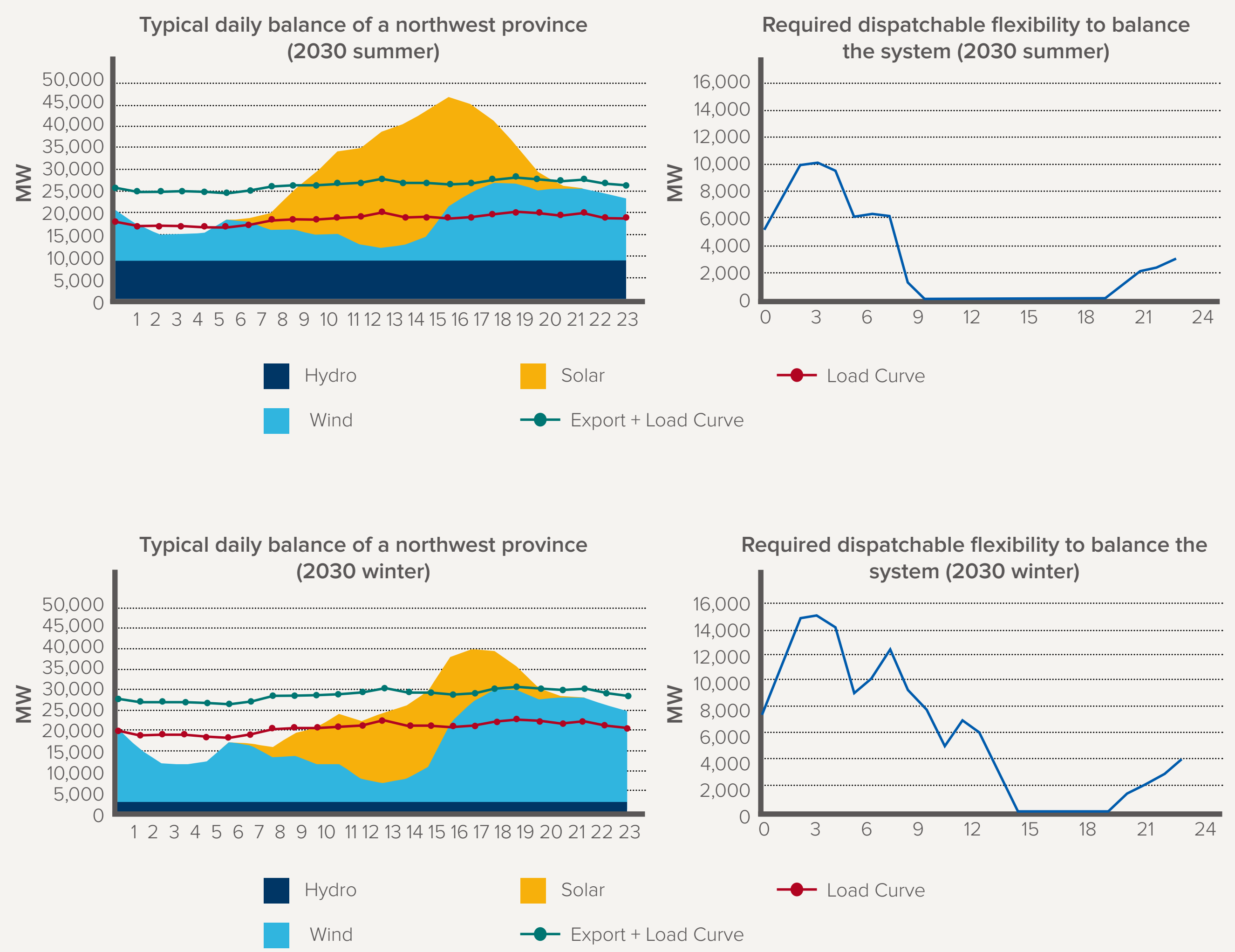
A Typical Energy-Importing Province in Central China in 2030[xiii]



[xiii] The charts for 2030 are based on public sources and basic assumptions. The data and chart don't convey the complexities of the expected situation.

EXHIBIT 28

A Typical Energy-Exporting Province in Northwest China in 2030



While the assumptions used here are illustrative and unrealistically simple, they define the fundamental problem. The higher the VRE share, the greater the danger that inflexible import/export contracts and inflexible hydro resources will impose an impossible or prohibitively expensive demand on coal flexibility. Fixing these problems will ensure more than adequate flexibility in the period to 2030. Beyond then further flexibility resources will need to be developed.

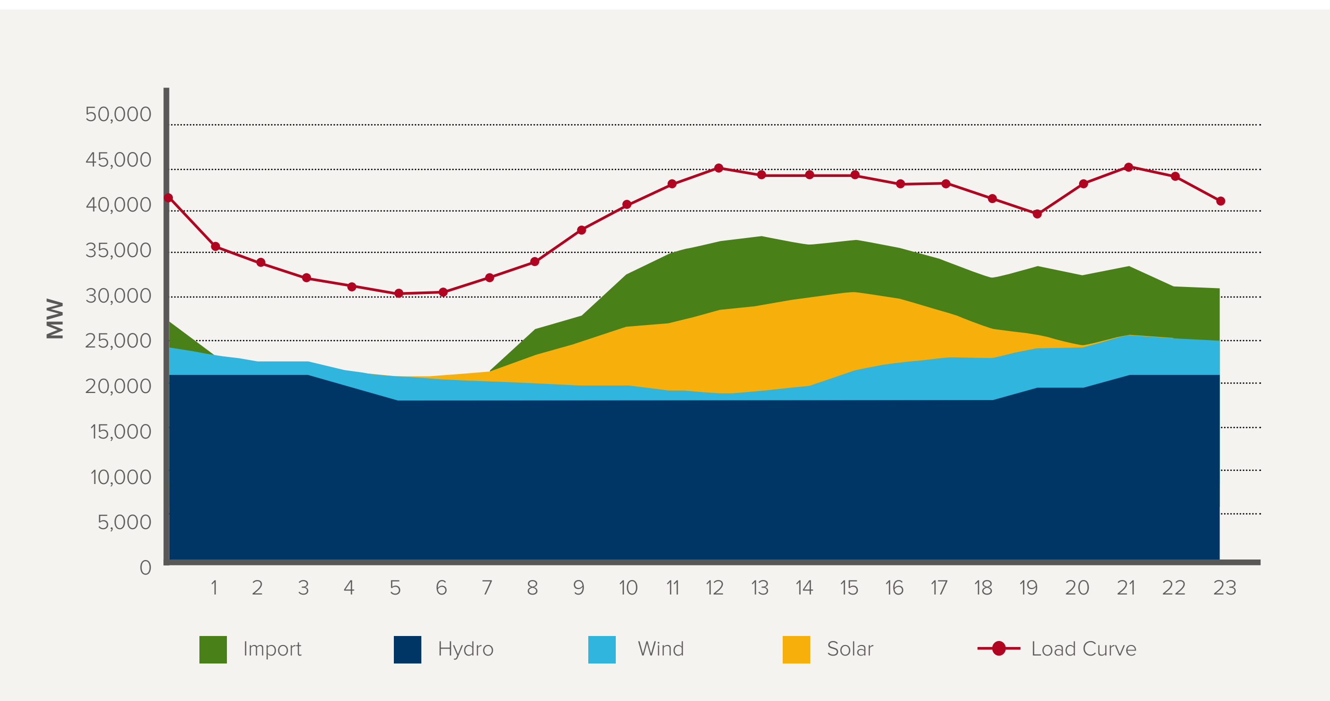
More flexible interprovincial transactions

At present most contracts for interprovincial export/import through long-distance HVDC lines are still annual contracts with a pre-set delivery schedules allowing limited flexibility for day-to-day variation. To make this fixed supply possible, and to ensure high utilisation of HVDC lines, varying renewables output is combined with thermal output in exporting provinces, which also reflects provinces' perceived incentives to maximise provincial GDP.

But as Section 3 described, there is no necessity to run HVDC lines at high and constant utilisation rates. More flexible interprovincial energy contracts could create a better match between renewable supply curves in exporting provinces and demand curves in importing ones. For instance, if the summer-time imports of the typical importing province shown in Exhibit 27 could vary in line with its demand, this would simultaneously reduce both the required variation in the importing province's thermal output and solar curtailment in the exporting province (see Exhibit 29). This would involve a ramp up between 7:00 a.m. and 10:00 a.m. and nil delivery between 1:00 p.m. and 7:00 p.m.

EXHIBIT 29

An Energy-Importing Province with Adjusted Flexible Import Schedule (Summer)



Increasing coal plant flexibility

Coal plant flexibility in power systems is influenced both by physical capabilities and by the market mechanisms in place and the incentives that they create. Policy should secure increased flexibility along both dimensions:

- **Feasible physical flexibility.** Coal plants are inherently less flexible than gas plants along two dimensions—the pace at which they can ramp up capacity utilisation, and the speed with which they can start generating in either a "hot start" or "cold start." On the third dimension of flexibility—the minimum feasible run rate—both gas and coal plants face important limits. But new technologies are continuing to improve feasible flexibility along all three dimensions, with gradual reductions in minimum run rates, increased feasible ramp rates, and some reduction in start times. Exhibit 30 shows the difference between commonly used power plants and advanced plants in China.

  Chinese plants are on average fairly advanced. Most coal power plants can run at the minimum level of 50%, and 600 MW level units could even run at 40% without retrofits.[30] Retrofitted coal power plants can run at 30%–35%, and some advanced plants could even run at 20%–15%.[31] If coal power plants are used for heat meanwhile, the minimum run rate would be about 20%–30% higher. Thus, there is still significant opportunity for improvement.

  The 13th Five-Year Plan set targets to improve minimum run rates on 220 GW of coal plants from 55% to 30%–40% for electricity-only plants, and for 70%–80% to 50% for CHP plants. This would deliver an additional flexibility resource of around 20% of total nameplate capacity, about 44 GW in total. However only 58 GW of this 220 GW target has so far been achieved.[32] Meeting the 13th Five-Year Plan objective and extending flexibility to as much of the coal fleet as possible should be a high priority.

- **Market contract flexibility.** Until 2015, China allocated most of its generation equally to each coal plant and dispatched them in a pre-determined schedule. Although more than 30% of generation has moved to a market-based price,[xiv] the majority of plants are still being paid at a fixed price for each kwh of power they generate. These are following an assigned schedule from the dispatch centre, providing no incentives for flexible generation. Some ancillary service market payments have now been introduced to encourage more flexible operation for coal plants in the absence of an energy spot market.[xv]

  These market reforms must be extended further in the future. As power systems transition to high VRE and other zero-carbon generation shares, thermal generation shares should and will decline, but thermal plants are likely to play roles as flexible back-up for the next 20 years, alongside other competing flexibility sources. Power markets will therefore need to provide high-priced remuneration for peak energy supply in order to remunerate thermal plants for the flexible services they provide; payments for capacity provision might also play a useful role.

[xiv] This refers to the mid-to-long term market price.

[xv] In China, the ancillary market usually contains frequency regulation services and deep ramping services (units get paid when operating under a certain output level). These markets are designed under current dispatch protocol with no energy market and are focused on compensating generators for diverging from default/base-load dispatch. While many of the services in China's market may share the names of ancillary services internationally, they have a substantially different meaning.

EXHIBIT 30

Typical Thermal Plant Flexibility in China[33]

	Commonly used power plants	Advanced power plants
Minimum load (% PNom)	Condensing unit: 50%–60% CHP: 60%–70%	Condensing unit: 30%–35% CHP: 40%–50%
Average ramp rate (% PNom per min)	1%–2%	2%–5%
Hot start-up time (h)	3–5 h	1.5–4 h

Increasing hydro supply flexibility

For hydro as for coal, there are two key issues: the inherent physical flexibility of China's hydro resources, and the impact of contracts and incentives on the flexibility with which hydropower is used. Improving the former may require significant investments, but the latter could be rapidly improved via power market reforms.

Analysis conducted by the China National Renewable Energy Center (CNREC) in 2018 suggests that there is major opportunity for market and contract reforms to make hydro a far more flexible resource for daily supply/demand balancing (Exhibit 31).[34] While in 2020 hydropower can vary in a range between 100 and 200 GW on a daily cycle, CNREC believes that it could vary as widely as 60 GW to over 300 GW by 2035, with a slight further increase in flexibility by 2050. If such flexibility can indeed be achieved, this will greatly ease and reduce the costs of transition to VRE penetration levels well beyond the 28% illustrated in Exhibit 2.

Policy should therefore place a strong focus on:

- Identifying and implementing cost-effective investments to increase physically feasible flexibility; and

- Reforming market and contract structures to encourage flexible use of hydro resources.

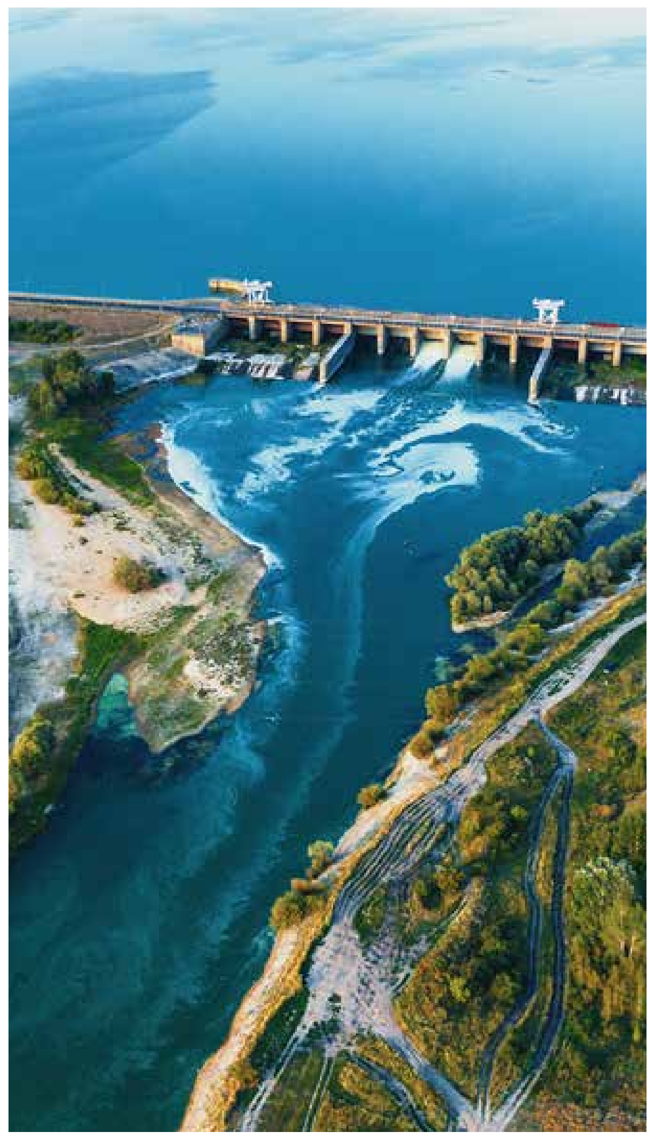
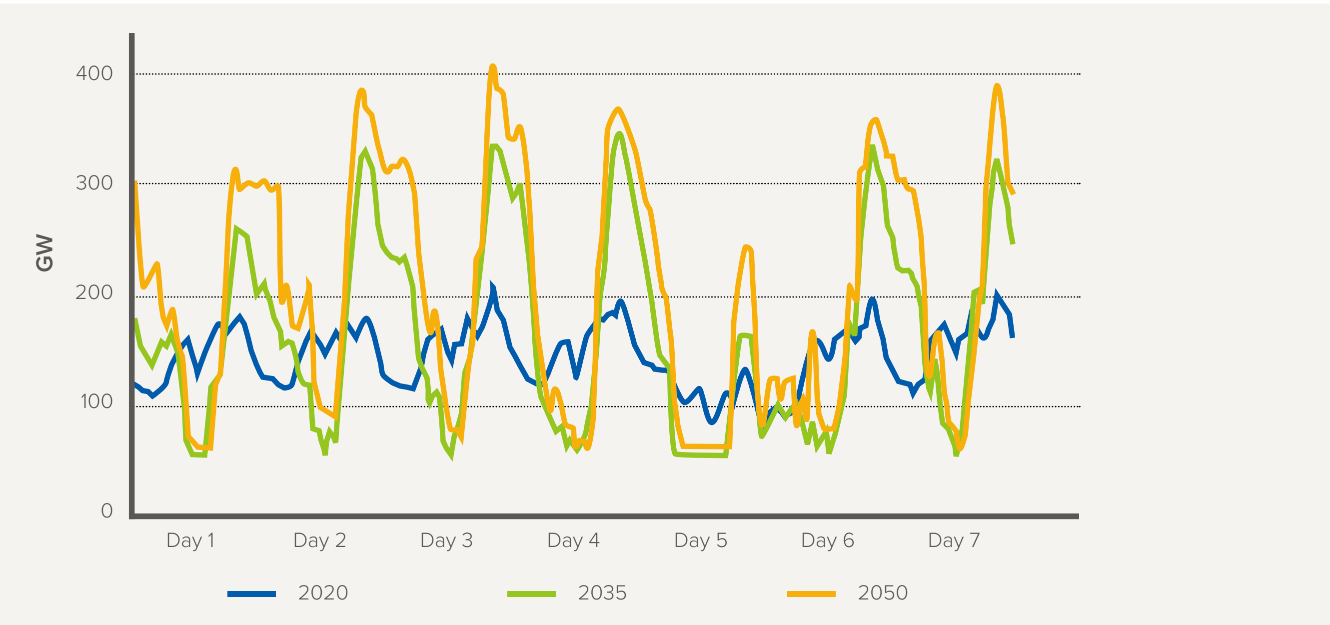


EXHIBIT 31

China Average Summer Week Hydropower Generation Curves[xvi]



Source: NDRC Energy Research Institute

Long-term flexibility options: batteries, hydrogen, and demand response

By combining the three flexibilities—interprovincial, coal, and hydro—China's power system can easily integrate the growth of renewables to 28% of total generation by 2030 and to much higher levels by the mid-2030s. Scenarios presented by the CNREC in 2018 illustrate a scenario for 2035 in which the vast majority of flexibility would then derive from thermal plants and hydro flexibility with only a moderate role for electricity storage in battery form (Exhibit 32).

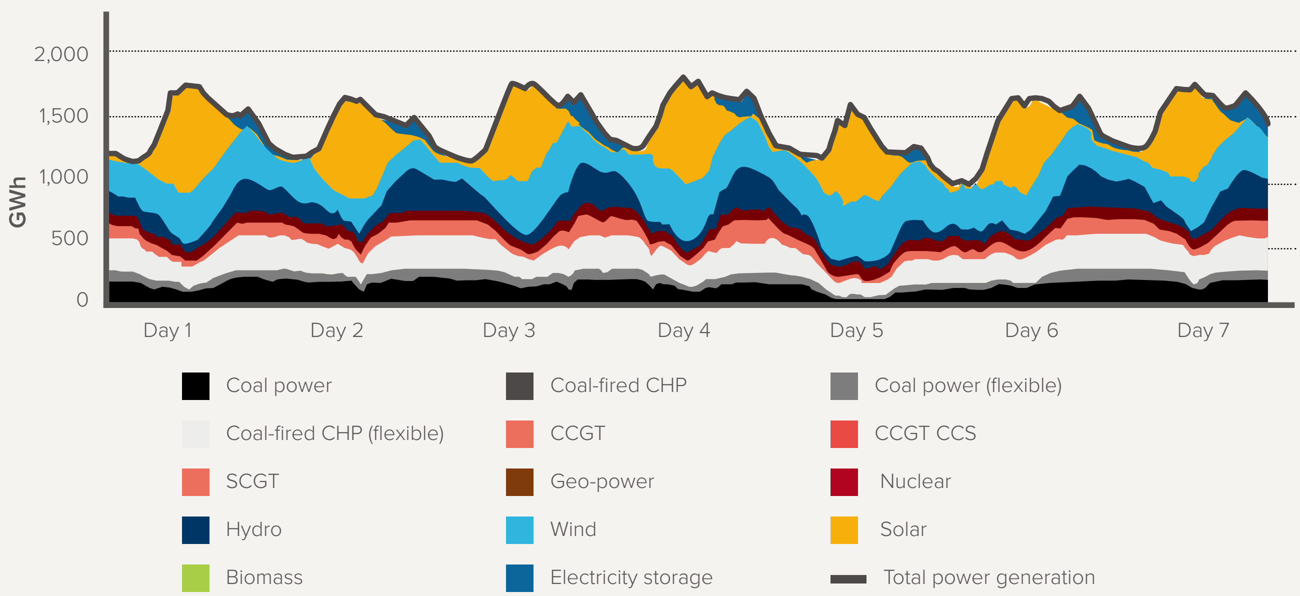
But as VRE penetration continues to grow rapidly in the 2030s and early 40s, new forms of flexibility will become more important. Three technologies will be particularly vital and China is excellently placed to be a global leader in each of them. Policies put in place today, including in the 14th Five-Year Plan, should foster their early development.

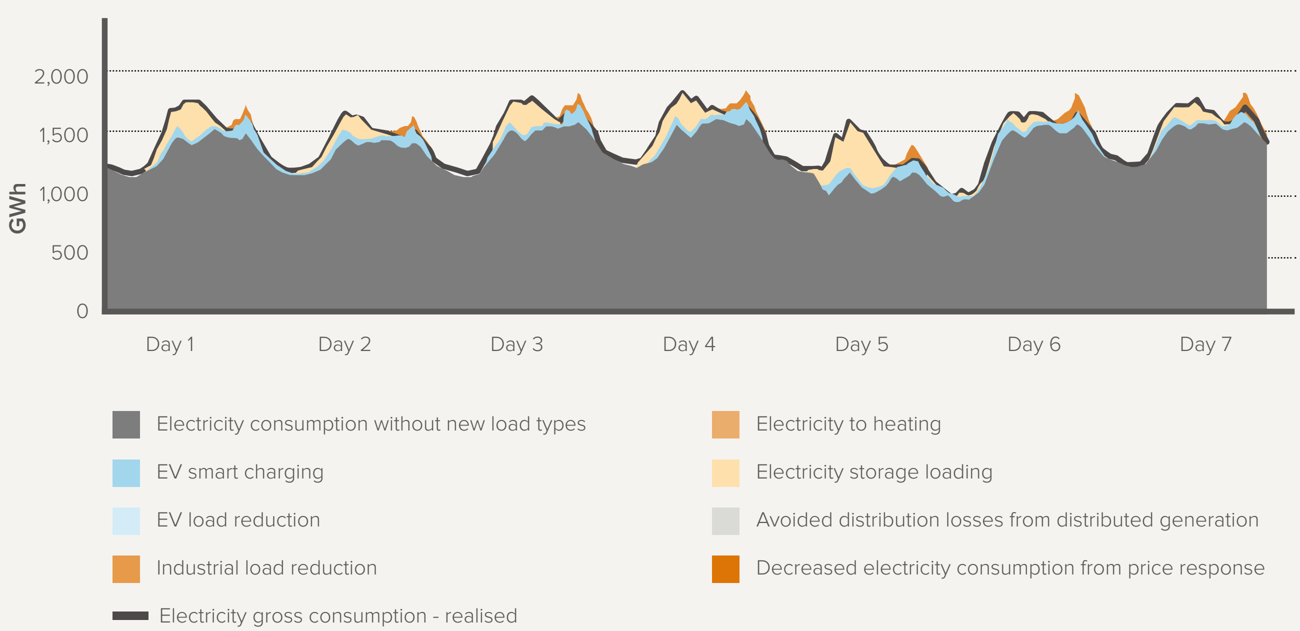
- **Battery storage** will become increasingly important and economic. Continued cost reduction will be driven by the EV industry in which China is a leader and stationary energy storage systems (ESS) will become increasingly economic over time. China should therefore encourage the early development of this ESS industry by introducing auctions for ESS as an alternative provider of frequency control, ramping, and daily demand balance services.

[xvi] "The Stated Policy scenario is based on the current and stated policies regarding the energy transition, climate policy, and environmental policy. The Stated Policy scenario has a lower deployment of renewable energy after 2020, and a higher consumption of coal, oil, and natural gas than the Below 2°C scenario, and the electrification of end-use consumption is also less than the Below 2°C scenario."- *China Renewable Energy Outlook* (CREO 2018) by CNREC

EXHIBIT 32

Power Generation and Consumption Profile in China in 2035, Summer (Stated Policy Scenario)[35]





Source: NDRC Energy Research Institute

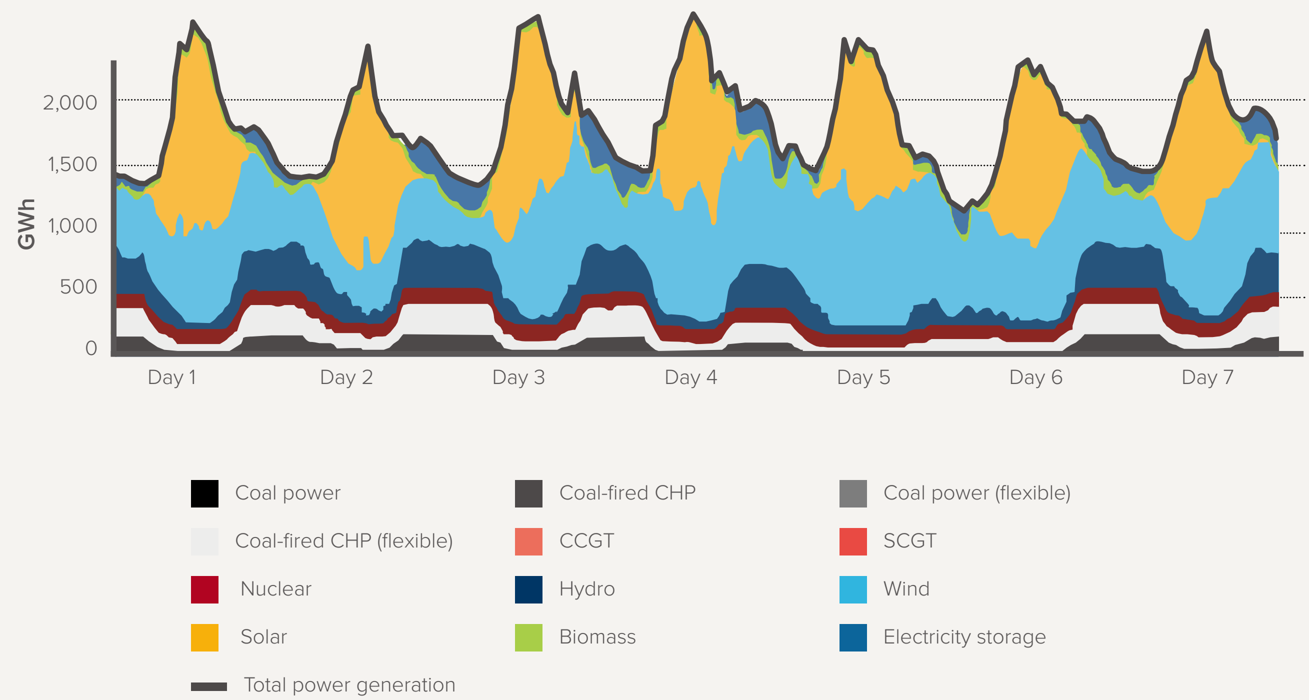
- **Demand response** will also play a vital role particularly over the daily cycle in China. As the CNREC report suggests, this role is likely to develop gradually through the 2020s, but should subsequently become a vital part of the system alongside battery storage. Given its long-term strategic role, the development of demand response in the 2020s is extremely critical. This will involve shifting some EV charging from an early evening peak to coincide with high solar output in the middle of the day. Meanwhile, midday battery storage and evening discharge will need to shift supply in the other direction (Exhibit 33).

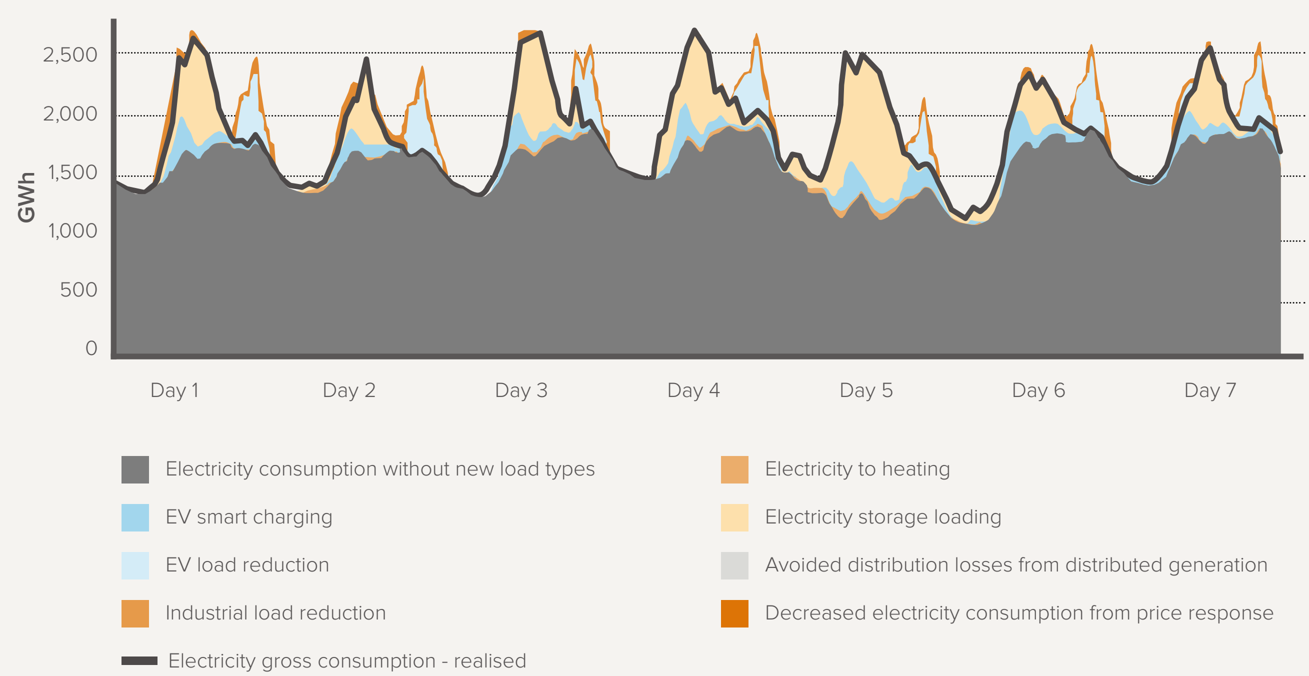
  China is well placed to be a leader in the application of this technology, given its strength in multiple forms of software and network applications, and the opportunity to define common standards in the world's largest market. Investments in "new infrastructure"—including AI, 5G, and smart grids—have already been identified as crucial priorities over the next five years.[36] Detailed implementation of these investments should be designed to ensure rapid development of smart demand management systems and markets.

- **Hydrogen**—produced via electrolysis and burnt in gas turbines—is likely to play a significant role of seasonal supply/demand management over the long term. China is already leading the world in cost reduction of electrolyser capital equipment. China should foster the development of green hydrogen, for instance via clear quantitative targets and initial subsidies of the sort that the European Union is now deploying. This will not only provide China with a potential competitive advantage in low-cost production but will also create the potential for low-cost renewable electricity storage when this becomes needed.

EXHIBIT 33

Power Generation and Consumption Profile in China in 2050, Summer (Below 2°C Scenario)[37]





Source: NDRC Energy Research Institute

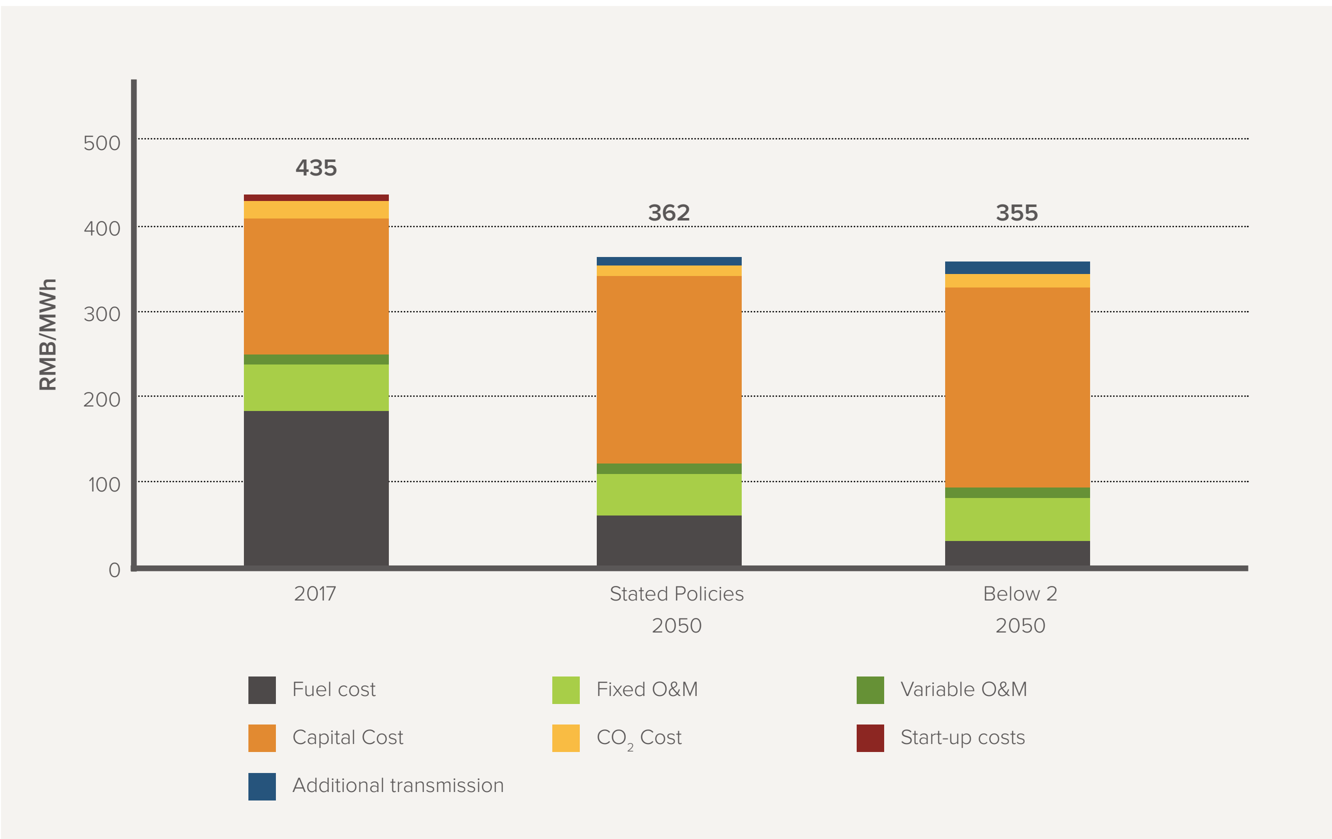
Total system costs in China

In China as elsewhere, some forms of increased flexibility will add to total system cost. However, some (e.g., batteries and hydrogen) will enjoy declining costs over time, and demand response creates opportunities to reduce total system cost. Also, the costs of renewable and other zero-carbon power generation will be significantly below those of thermal power production.

As a result, estimates for China mirror the global picture presented in Exhibit 34, with total system costs for low/zero-carbon systems likely to be below those for today's fossil fuel-based systems.

EXHIBIT 34

Comparison of System Costs in 2017 and 2050 under Different Scenarios



Source: NDRC Energy Research Institute

5 POLICIES TO ACHIEVE THE 2030 OBJECTIVE

POLICIES TO ACHIEVE THE 2030 OBJECTIVE

There is no doubt that it is technically and economically possible for China to meet all future growth in electricity supply from zero-carbon sources, building no new coal plants from now on. Such a strategy would put China on a path to achieve carbon neutrality by 2060, with full decarbonisation of the power system at least 10 years before that. On the other hand, new coal investments in the 2020s will make achieving the carbon neutrality goal far more difficult and will waste investment on assets that will become stranded in the future and will need to be closed down before the end of their useful lives.

It is therefore essential that policies—and in particular the details of the 14th Five-year Plan—are aligned to achieve the objective of zero-carbon growth.

- The most important policy required to make this possible is clear quantitative targets combined with contract structures for renewable energy generation that provide certainty and drive down costs.

- This should be supported by market reforms to enable efficient supply/demand balance, market and technical actions to support effective short-term grid management, and better data availability to support improved decision-making and innovation.

CLEAR QUANTITATIVE TARGETS AND POLICIES TO ENSURE DELIVERY

Across the world, renewable electricity generation costs are now falling below fossil fuel costs and will fall much further if the volume of investment continues to rise. As a result, the need for explicit subsidies—paying prices which are expected to be above the thermal power price—has either disappeared or soon will.

But this does not mean that a completely free-market approach is now optimal. The pace of cost reduction is itself dependent on how rapidly the volume of renewable investment rises and on the perceived risk of renewable energy investments (which determines the required rate of return). Optimal power market policy should now therefore combine clear quantitative targets with mechanisms to ensure competitive pressure for cost reduction. Policies to ensure easy grid interconnection are also vital and long-term private contracts should also be encouraged.

Quantitative targets for 2030 and the 14th Five-Year Plan

Quantitative targets will enable the Chinese wind and solar development and supply industries to achieve the economies of scale and learning curve effects that make cost reduction possible. Both ten-year and five-year targets are important:

- A ten-year perspective is essential to avoid a repeat of the slowdown in development that occurred in the latter years of the 13th Five-Year Plan as many provinces hit their installation targets early. A guiding principle of “all new electricity growth from zero-carbon sources” should therefore be established and translated into an indicative penetration target for zero-carbon generation, such as the 53% shown on Exhibit 2.

- But it is also essential to establish penetration and capacity growth targets for the 14th Five-Year Plan, broken down into year-by-year objectives and with requirements set on a province-by-province basis.

To achieve the objective of “all new electricity growth from zero-carbon sources,” capacity targets will need to be broadly in line with those set out in Exhibit 2, with:

- Both wind and solar capacity growing at about 50–60 GW per year to reach over 800 GW of both by 2030

- Nuclear and hydro also growing in line with existing plans to reach about 120 GW and 440 GW respectively by 2030

- A ban on new coal investments beyond those coal plants already under construction[xvii]

Policies to achieve delivery

To ensure both rapid development of renewable energy and further cost reduction, it is essential to have contract structures that continue to provide renewable energy developers with certain long-term prices for a significant share of output. There are a range of different means to achieve this, reflected both in China's current approach and international practice. An optimal way forward is likely to include a mix of:

- **Continuation of the subsidy-free regime for solar/wind interconnect at the coal benchmark price.** As the economics of wind and solar are continuously improving, contracting at benchmark price for onshore wind and solar will generate an increasing premium for new projects, incentivizing rapid deployment in the near-term.

- **Continued use of auctions to ensure intense competition.** China should also consider the use of competitive auctions for specified quantities of wind and solar development, giving successful bidders a certain fixed price for a significant share of their generation. Over time, bid prices will increasingly fall below the current coal benchmark price. Auctions of this sort should be deployed to the extent that the other delivery policies are insufficient to meet provincial targets.

- **Incentives for long term private contracts.** In most countries, government-organised contracts such as the two types described above have been the main driver of renewable energy development. But in some countries, in particular the United States, private long-term supply contracts ("PPAs") have also played a major role. Optimal policy should therefore supplement publicly organised auctions with incentives for major private power users to strike long-term supply contracts direct with suppliers. The renewable energy consumption percentage target scheme (often referred as "RPS") will help achieve this.

All of these will need to be supported by clear rules to enable easy grid connection and to reduce the cost of interconnection.

MARKET AND GRID REFORMS TO SUPPORT FLEXIBLE POWER

As renewable generation costs fall and penetration increases, the key challenge in power systems switches from generation cost reduction to the issues discussed in Section 4 *Balancing Supply and Demand by Hour, Day, and Season.* In part, this is a technical issue that could be addressed through technology innovation and investment to increase the potential flexibility of coal plants and hydro plants. But the most important priorities are market and grid management reforms to enable flexible use of all resources, supported by better data availability.

- **Better wholesale markets for short-term energy trading:** Inadequate price signals and economic incentives currently result in less flexible thermal and hydro operation than possible. A greater role for short-interval day-ahead and real-time markets could better reflect the output variations from VRE and stimulate all system resources to respond to the system needs by following the price signal.

  International experience demonstrates the potential of this approach and from June 2019 China has piloted a spot market in eight provinces.[xviii] But in response to multiple stakeholder interests and resistance, a large share of generation still follows

[xvii] A comprehensive fiscal reform where the local government can be remunerated through its net-reducing carbon efforts should be developed to support this target.

[xviii] ERCOT has applied a five-minute market that has successfully encouraged units to change their operation level rapidly to obtain higher revenue. In this way, even with fast-growing renewables, ERCOT didn't see a big increase in the required ancillary services since much of that flexibility has been incentivised by a well-designed energy market.

the old long-term fixed price and dispatch plan, hindering progress towards greater flexibility.

- **Opened markets for all participants:** Both short-term energy markets and ancillary service markets should also be open to all types of technology.[xix] Having closed markets can undermine market effectiveness and result in suboptimal dispatch. It can also impede the development of new technologies that will be increasingly needed to balance the system as zero-carbon shares grow to high levels beyond 2030. For example, batteries can only get paid for ancillary services in a few provinces and there is no daily operated market for battery-based demand response to participate.

- **Coordinated and flexible inter-provincial dispatch:** As Section 4 also discussed, China would have no difficulty balancing supply and demand in 2030 if it operated as a single electricity system. And with only two major grid companies running the system, China should be well placed to build regional markets or well-coordinated interprovincial trading. But inflexible interprovincial contracts and incentives make achieving balance more difficult. Policies to address this should entail:

  - Expanding the balancing zones and developing a coordinated cross-system dispatch; and

  - Allowing inter-provincial trading to respond to short-term provincial price signals and balancing dynamics, versus today's system in which prices and volumes are scheduled on an annual basis.

- **A technology-neutral capacity market:** Well-functioning energy markets could themselves provide adequate incentives for flexibility (and should be the priority), but increasingly flexible thermal plants could also be remunerated via markets for capacity provision. For instance, this would create incentives for CCGT investment even if a plant will only be needed for a small number of hours per year. Any such capacity markets should be "technologically-agnostic" to ensure incentives for the development of the full range of zero-carbon storage options—e.g., batteries or hydrogen—which will be increasingly required over time.

- **Transparent data disclosure:** Diverse market participation and fair competition could drive innovation and lower costs of flexibility provision; this requires equal access to information, such as load profile and load forecast. But with a few major players currently owning and controlling proprietary data, new participants have found it difficult to compete effectively. Thus, it is important to set industry data disclosure standards, including data types, granularity, and disclosure frequency.

IMPROVE POWER PLANNING PROCESSES TO SUPPORT VRE

Greater granularity of forecasts is also required to inform both grid planning and private investment plans.

- **Comprehensive and granular load forecasts:** The data that utility/grid companies currently publish on load patterns, which often show only a single average annual peak load number, can create a bias towards thermal investment and against other storage or peak supply options. Detailed data on actual daily load patterns throughout the year and forecasts of how the these might evolve as demand grows would enable more efficient VRE development.

- **Grid infrastructure to align with VRE growth:** As VRE penetrates, it is critical to align grid upgrade planning at both transmission levels and distribution levels with long-term renewable quantitative targets.

[xix] Renewables may stay with the current practice until the market structure is well implemented.

Also, transparent disclosure of methodologies of assessing future renewable integration capability will equip developers with future visibility to develop long-term development plans and lower non-technical costs of renewable energy development.

TECHNICAL AND MARKET ACTIONS TO SUPPORT SHORT-TERM GRID MANAGEMENT

As Section 2 described, it is clearly technically feasible to manage a system with shares of VRE far above the 28% that Exhibit 2 envisages by 2030. This will require:

- **Effective markets for ancillary services,** such as very short-term frequency balance. As with short-term energy market and capacity markets, these should be developed on a "technology-agnostic" basis.

- **Technical regulations upgrade.** Technical requirements, grid connection rules, and processes as described in Section 2, should ensure system stability in the face of growing renewables shares, covering in particular:
    - Improved forecasting of VRE output to prevent avoidable renewable curtailment and reduce unnecessary system reserves.
    - Tighter grid regulations on wind farm ramping to reduce steep wind output variation and resulting system impacts.
    - Mandatory requirements for HVRT to enhance VRE's performance during system disturbance and avoid cascading failure.
    - Careful quantification and management of system inertia to ensure system reliability as VRE penetration grows.

APPENDIX

APPENDIX

EXHIBIT A

2030 Zero-Carbon Investment Scenario Assumptions

Generation (TWh)	2019	New generation	2030	Mix %
Coal	4,554	202	4,756	43%
Natural Gas	233	132	365	3%
Solar	224	887	1,110	10%
Wind	405	1,364	1,769	16%
Offshore Wind		251	251	2%
Hydro	1,270	371	1,641	15%
Bio	111	133	244	2%
Nuclear	349	516	865	8%
Total generation	7,325	3,975	11,000	

Total Capacity (GW)	2019	2030	New capacity	New capacity per year
Coal	1,041	1,041	0	0
Natural Gas	90	140	50	5
Solar	204	854	650	59
Wind	204	804	600	55
Offshore Wind	6	66	60	5
Hydro	328	440	110	10
Bio	23	50	27	2
Nuclear	49	120	71	6

ENDNOTES

ENDNOTES

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