China Energy Transformation Outlook

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"China will strive to peak carbon dioxide emissions before 2030 and achieve carbon neutrality before 2060. This requires tremendous hard work, and we will make every effort to meet these goals."

President Xi Jinping

Statement at the General Debate of the 76th Session of the United Nations General Assembly, September 2021

Preface

China has set up clear ambitions to implement a profound energy transformation. With the statement from President Xi Jinping on 22 September 2020, China has significantly stepped up the commitment to strive to peak CO_2 emissions before 2030 and achieve carbon neutrality before 2060. Thereby the previous commitment to a green development pathway has been reconfirmed. President Xi has introduced the new energy security strategy featuring Four Reforms for improving the energy consumption structure, building a more diversified energy supply structure, improving energy technologies to upgrade the industry, and optimising the energy system for faster growth of the energy sector, and One Cooperation, which is international cooperation to achieve energy security in an open environment. The 19th National Congress of the Communist Party of China further promotes the ambitions to build a clean, low-carbon, safe and efficient energy system.

While the climate goals are clear, the pathways for the energy transformation call for clarification. The energy transformation must achieve multiple objectives aside from climate goals. China is still in the developing phase of economic development. The energy transformation should support the overall economic growth and ensure a just transformation, considering the destruction and creation of jobs and local challenges in transitioning from fossil fuels to clean energy. Furthermore, the transformation must balance the urgent need for CO_2 emission reductions with time to develop new technologies, new policy instruments, and a genuine penetration of the transformation policies into all layers of decision-makers.

This year's China Energy Transformation Outlook, CETO 2022, focuses on two different energy system scenarios for energy transformation. The first is the baseline scenario, where China contributes to the global 2-degree goal and achieves carbon neutrality around 2070. The other scenario shows a path to meet the climate targets to peak CO_2 emissions before 2030 and reach carbon neutrality before 2060. Also, the report includes several thematic analyses, including end-use transformation, power sector transformation, power market reforming, power-to-X, carbon pricing, status and prospects of CCUS in China.

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Table of Contents

***Preface* 1**

***Table of Contents* 2**

***The CETO 2022 team* 4**

***Abbreviation list* 5**

***Key findings* 8**

The foundation for China's energy transformation 8
The CETO scenarios 9
Key results for the two scenarios 10
Policy recommendations 11
Additional key findings from the Outlook research 14

Part 1: Energy Transformation Status 17

***1 The global quest for carbon neutrality* 18**

1.1 Key messages 18
1.2 We are in a climate crisis, and it will be worse in the future unless we see immediate action 18
1.3 IEA and IRENA report on net-zero pathways for the energy sector..... 20
1.4 Regional and National quests for carbon neutrality 22
1.5 U.S.-China Joint Glasgow Declaration on Enhancing Climate Action in the 2020s.. 28

***2 The Chinese energy system today* 30**

2.1 Key messages 30
2.2 Overview of energy consumption 30
2.3 Overview of primary energy production 35
2.4 Overview of energy balance 36
2.5 Overview of energy transition 37

Part 2: The Chinese pathway to Carbon Neutrality 41

***3 The Chinese energy system transformation to 2060* 42**

3.1 The CETO 2022 scenarios 42
3.2 Main Scenario Assumptions 43
3.3 Policy instruments for the transformation by sector.......................... 48
3.4 Scenario results 1.. 49
3.5 Scenario results 2 56

3.6 General conclusions from the scenario studies 69

4 End Use Energy Transformation 71

4.1 Key messages...71
4.2 General trend 72
4.3 Industry sector... 78
4.4 Transport sector 86
4.5 Building sector... 97

5 Power sector transformation 101

5.1 Key messages 101
5.2 Structural transformation of electricity supply and demand 103
5.3 Flexibility and system integration 115
5.4 Power market reform.. 124
5.5 Power transmission and grid infrastructure planning 137

Part 3: Thematic analyses 145

6 Power-to-X in the Chinese energy system 146

6.1 Key messages... 146
6.2 PtX in a Chinese context 147
6.3 Introduction to a study comparing two provinces............................ 150
6.4 Comparative study of PtX – the cases of two Chinese provinces....... 160

7 Carbon pricing 176

7.1 Key messages...176
7.2 Carbon pricing internalises the costs of emissions 176
7.3 China launched national ETS in 2021 177
7.4 National ETS shall switch from intensity-based target to absolute reduction target 178
7.5 Carbon price outlook scenarios...179
7.6 Carbon tax in certain sectors 180
7.7 Carbon pricing and other RE support..181

8 Status and Prospects of CCUS Development in China 182

8.1 Key messages... 182
8.2 Overview of CCUS development in China 183
8.3 A Simplified SWOT Analysis of CCUS Development in China 187
8.4 Concluding remarks...191

References 194

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Abbreviation list

ACCA21	Administrative Center for China's Agenda 21
AEC	Alkaline
AFOLU	Agriculture, forestry and other land use
AR6	Sixth Assessment Report
BECCS	Bioenergy with Carbon Capture and Storage
BECCUS	Bioenergy with CCUS
BEV	Battery Electric Vehicles
BLS	Baseline Scenario
CAPEX	Capital Expenditures
CBA	Cost Benefit Analysis
CBAM	Carbon Border Adjustment Mechanism
CCCPC	Central Committee of the Communist Party of China
CCER	Chinese Certified Emission Reduction
CCS	Carbon Capture and Storage
CCUS	Carbon Capture, Utilization and Storage
CDM	Clean Development Mechanism
CESO	China Energy Supply Optimization
CETO	China Energy Transformation Outlook
CHP	Combined Heat and Power
CNOOC	China National Offshore Oil Corporation
CNPC	China National Petroleum Corporation
CNREC	China National Renewable Energy Centre
CNS	Carbon Neutrality Scenario
CO_2	Carbon Dioxide
COP 26	The 26th UN Climate Change Conference of the Parties
CSG	China Southern Power Grid
CSP	Concentrating Solar Power
DAC	Direct Air Capture
DEA	Danish Energy Agency
DRI	Direct Reduced Iron
DSM	Demand Side Management
DSR	Demand Side Response
EAF	Electric Arc Furnace
ECBM	Coal Bed Methane Recovery
ECECP	EU-China Energy Cooperation Platform
EDO	Electricity and District Heating Optimisation
EOR	Enhanced Oil Recovery
ERI of NDRC	Energy Research Institute of the National Development and Reform Commission
ETS	Emissions Trading System
EU	European Union
EV	Electric Vehicles
FACTS	Flexible Alternating Current Transmission System
FCV	Fuel Cell Vehicle
FLHs	Full-Load Hours

FT	Fischer-Tropsch
FYP	Five-Year Plan
GHG	Green House Gas
HFCs	Hydrofluorocarbon
ICE	Internal Combustion Engine
IEA	International Energy Agency
IGCC	Integrated Gasification Combined Cycle
INDC	Intended Nationally Determined Contribution
IPCC	Intergovernmental Panel on Climate Change
IRENA	International Renewable Energy Agency
km	Kilometers
KSG	The German Climate Change Act ("Klimaschutzgesetz")
LCOE	Levelised Costs of Energy
MEE	Ministry of Ecology and Environment
MEM	Ministry of Emergency Management
MIIT	Ministry of Industry and Information Technology
MNR	Ministry of Natural Resources
MoF	Ministry of Finance
MoHURD	Ministry of Housing and Urban-Rural Development
MoST	Ministry of Science and Technology
Mt	Million tons
MWR	Ministry of Water Resource
NBS	National Bureau of Statistics
NDAM	National Day-Ahead Market
NDC	Nationally Determined Contributions
NDRC	National Development and Reform Commission
NEA	National Energy Administration
NEV	New Electric Vehicles
NLGACCECER	National Leading Group to Address Climate Change and Energy Conservation and Emission Reduction
Norad	Norwegian Agency for Development Cooperation
NO_X	Nitrogen Oxide
OECD	Organization for Economic Co-operation and Development
P2H	Power to Hydrogen
PEM	Polymer Electrolyte Membrane
PHEV	Plug-in Hybrid Electric Vehicle
PMCD	Provincial Market Operator with Central Dispatch
PMO	Provincial Market Operator
PPAs	Power Purchase Agreements
PSA	Pressure Swing Adsorption
PtX	Power-to-X
R&D	Research and Development
RE	Renewable Energy
RWGS	Reverse Water Gas Shift
SAMR	State Administration for Market Regulation
SASAC	State-Owned Assets Supervision and Administration Commission

SERC	State Electricity Regulatory Commission
SETC	State Economic and Trade Commission
SGCC	State Grid Corporation of China
SO_2	Sulfur Dioxide
SOEC	Solid Oxide Electrolysis
SOEC	Solid Oxide Electrolysis
SOEs	State-owned Enterprises
SPC	State Power Corporation
SPE	Solid Proton Exchange Membrane Electrolysis
SWOT	Superiority Weakness Opportunity Threats
TFEC	Total Final Energy Consumption
TPEC	Total Primary Energy Consumption
TPEP	Total Primary Energy Production
TPES	Total Primary Energy Supply
UHV	Ultra-High Voltage
UN	United Nations
US	United States
VALCOE	Value Adjusted Levelised Costs Of Energy
VPP	Virtual Power Plant
VRE	Variable Renewable Energy

Key findings

The foundation for China's energy transformation

China is today at a crossroads for the development of the energy system. Summing up the history of China's energy and economic development since the reform and opening up, the principal contradiction in energy development has changed. For an extended period, the principal contradiction was between the insufficient supply of total energy and the need for economic and social development. Today, the contradiction is between the high-carbon structure of energy supply and sustainable economic and social development. The central aspect of the conflict has also changed, from ensuring the supply of coal to meet the shortage of total supply in the past to vigorously developing renewable energy sources such as wind, solar and hydro energy to optimise the energy supply structure and promote the transformation of the energy system into a low-carbon or even zero-carbon system.

China's roadmap for energy development is a choice between the old roadmap and the new roadmap. The old path is the so-called successful path that other countries have already taken, including several developed nations: from coal to oil and gas, followed by a switch from oil and gas to renewable energy. This path contains several problems: It is too slow to meet the Paris Agreement requirements. It will jeopardise the security of energy supply and environmental safety, and it sets the economy under severe risks due to the international demand for low-carbon produced goods. Furthermore, China risks missing the innovation opportunity related to green development, and the energy system will become more costly and needed in the medium and long term.

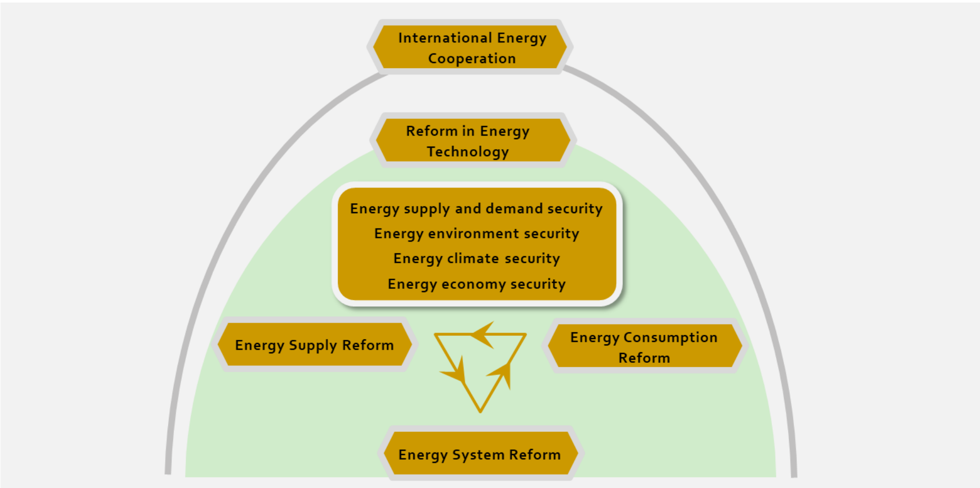
In contrast to the old path, China must follow the new roadmap introduced by the 19th CPC National Congress[1]: Build a clean, low-carbon, safe and efficient energy system as the core feature of a modern energy system. The energy development aims to achieve a sustainable balance between these features and even end up with a system where these features mutually reinforce each other. Hence, China must return to the energy security strategy of "Four Reforms and One Cooperation" proposed by the General Secretary in June 2014[1]. The strategy includes an energy consumption revolution as the key element, with an energy supply revolution as the foundation for the development.

The core of this "key" and "foundation" is to make energy production and energy consumption form an organic and seamless connection, which means that the green energy produced can be delivered to the consumer at any time and that the consumers prefer green energy instead of “black” energy. Production and consumption form a market cycle, and the effective interface between production and consumption and the proper functioning of the market needs to be supported by a revolution in the energy

[1] The new energy security strategy featuring Four Reforms and One Cooperation was put forward by Xi Jinping at the conference of the Leading Group for Financial and Economic Affairs under the CPC Central Committee held on June 13, 2014.

system. However, whether it is the energy production revolution, the energy consumption revolution, or the energy system revolution, none of them can be implemented without support from the technological revolution, which should be an efficient guarantee for the above three revolutions. In addition, under the general trend of global economic integration, the goal of building a community of common human destiny, and the irreversible trend of green and low-carbon transformation of global energy, no country or even enterprise can do it alone and needs to carry out extensive international cooperation in energy.

Figure 1: The internal logic of the Four Reforms and One Cooperation



The construction of a modern energy system is closely related to peak carbon dioxide emissions and achieving carbon neutrality and is a complex system project. As the General Secretary pointed out at the ninth meeting of the Central Finance and Economics Commission on 15 March 2021, "achieving peak carbon and carbon neutrality is an extensive and profound economic and social systemic change."[2]

Therefore, constructing a modern energy system also requires a systemic energy transformation. As long as China adheres to the general policy of "Four Reforms and One Cooperation", it is expecting to be able to complete the systemic energy transformation, build a modern energy system, and ultimately achieve energy supply and demand security, energy environment security, and energy climate security, thus guaranteeing national economic security.

The CETO scenarios

The scenarios in CETO comprise two development pathways for the Chinese energy system. The *Baseline Scenario* (BLS) shows a development, where China contributes to the global 2-degree goal and achieves carbon neutrality around 2070. A *Carbon Neutral Scenario* (CNS) illustrates the pathways for achieving the dual goals of peaking carbon dioxide emission before 2030 and achieving carbon neutrality before 2060.

The CETO scenarios provide a detailed outline of key components that should define China's Energy Transformation Strategy and the approach to achieving carbon neutrality.

This relies on four pillars and the last resort:

- **Energy efficiency** improvement on the demand side is needed to ensure the pace of supply-side deployments can keep up and sustain required economic growth.
- **Green energy supply –** technological progress and cost reduction make RE provide clean energy in bulk, mainly through renewable electricity.
- **Electrification** will support driving fossil fuels from end-use consumption, in conjunction with the decarbonisation of the electricity supply.
- **Hydrogen** becomes a vital energy carrier, which links the abundant supply of cheap green electricity and the hardest to abate sectors. Green hydrogen, combined with captured carbon, allows for creating fuels for heavy transport, shipping, and aviation sectors.
- **Sequestration** of CO_2 creates the backstop or last resort option, particularly with negative emissions and carbon sinks. Negative emissions can compensate for a modest level of emissions still in the system in 2060 (e.g., from incomplete capture of fossil plants with CCS).

To achieve carbon neutrality in practice, each of the above pillars relies on the previous. Without energy efficiency, the necessary pace of supply-side scale-up of green energy will require excessive capital, and the cost of useful energy services is expecting to be too high. Without a green electricity supply, electrification will only move emissions sources from end-use sectors to fossil-fuelled power plants. The hydrogen and PtX pathways are likely the more costly supply-side transformations and should serve the harder to transition demand-side transformations. Finally, intensive direct and indirect electrification creates opportunities for large-scale electricity consumption, which has a significantly higher potential for flexible operation than traditional costly and alternative storage options such as hydrogen or in consumption side batteries. The electrification process, which requires a green electricity supply, can provide the lynchpin making the necessary final increments of high penetration variable renewable energy (VRE) possible in the power sector.

Key results for the two scenarios

Continued economic growth can be supported while achieving carbon neutrality

The scenarios show the pathway for the transition of the energy system to a clean, low-carbon, secure and efficient energy system. The energy needed to support continued economic growth can be secured by promoting energy efficiency, electrification, and massive renewable energy deployment.

Energy efficiency improvement is a key pillar to drive down the overall energy demand

Despite a more than 4.2-fold increase in real GDP between 2020-2060, the final energy consumption can return to current levels by 2060. In both scenarios, the economy's energy intensity decreases to less than 23% of the 2020 level by 2060.

Electrification transforms the demand side

Direct fossil fuel consumption decreases in favour of electrification. Most significantly, the direct use of fossil fuels is switching to electricity in industry, transport and buildings sectors.

Renewable energy satisfies the bulk of the energy demand

The cost reduction of renewable electricity, the practical completion of market reforms, and the ability to scale up manufacturing allow wind and solar power to become the backbone of the energy system.

Power-to-X, carbon sequestration and carbon sinks are necessary to achieve the final steps towards carbon neutrality

China can reach a low-carbon energy system with a solid effort to improve energy efficiency, electrify the end-use sectors, and deploy renewable energy on the supply side. However, to reach carbon-neutrality, it is necessary to develop and deploy the power-to-X technologies, especially the production of green hydrogen, and remove CO_2 by sequestration and carbon sinks. These technologies play an increasing role in the energy system after 2035.

Policy recommendations

To achieve the carbon neutrality target by 2060 and establish a clean, low-carbon, safe, and efficient energy system, it is necessary to promote industrial electrification, green electricity, and the informatisation, digitisation and intelligence of the energy sector. Firstly, large-scale development and use of green electricity is key to the supply-side reform of the energy sector, facilitating the foundation of a new energy system; secondly, promoting the informatisation, digitisation and intelligence of the energy sector will support the energy sector's green, low-carbon transition; thirdly, optimising energy production should be guided by the end-use energy demand.

Take the large-scale use of green power as a breakthrough point, drive and conduct the modernisation and transformation of China's energy system

China should accelerate promoting wind and solar power to become the major power sources, and increasing green electricity supply. Both utility-scale and distributed onshore wind power should expand orderly, accompanied by the construction of power transmission lines and the amelioration of the power consumption market. Specifically, it is planned to orderly construct utility-scale wind bases in the Three-North and the middle provinces. Distributed wind power should be widely applied and used better due to the continuous advance of related technologies. In addition to meeting the demand for clean energy within the region, more inter-regional deployment of wind power is planned. Utility-scale solar farms are expecting to expand continuously, and the layout of these needs to be optimised. The development of solar power should be planned and performed from a broader view. China should conitue to construct more solar farms for inter-regional power transmission in resource-desirable regions, and for improving comprehensive land-use efficiency.

The energy transition towards renewable power should be coordinated with coal and gas power. It is important to improve conventional power regulation capabilities. To balance the interplay of competition and cooperation between coal power and renewable energy and green electricity means that the overall green, low-carbon transition, the control of total coal consumption, and the supply-demand reform of the energy sector should be considered as a whole system. Electric power industries and companies must shoulder more responsibility in this green electricity transition. We need to make good use of the existing coal power resources and accelerate the transformation of coal power flexibility by adding high-efficiency heat storage facilities to coal power plants to adapt to the rapid fluctuations of power system load and renewable energy generation, improving the flexibility of coal power, and shifting the role of coal power from the main bearer of the baseload to the provider of system flexibility. The completion rate of flexibility retrofit carried by existing coal power units should reach over 50% by 2025, and 100% by 2030. Better use of the coal power reduction and replacement, and the regulating function of gas power in window periods, can provide firm support for developing the high-penetration renewable energy system in the northwest and the distributed energy system in northern, eastern, and southern China.

To build a unified, open, and orderly competitive energy market system: a trading platform for coal, electricity, petrol, and natural gas enables the dynamic interaction between supply and demand; building a power market system including medium- and long-term trading, spot trading, and other ancillary services trading is a big step for founding the national power market and national carbon market. Improving the green certificate system by optimizing the trading methods, pricing and management involved in the green electricity and power certificate transactions and making it coordinate well with the carbon market.

The energy storage system development goal mainly focuses on pumped storage, electrochemical batteries, electric vehicles, and green hydrogen. Various energy storage technologies with different temporal and spatial characteristics enable the development of an overall “renewable energy + storage” system. Storage systems are not only the basic component of the on-grid renewable power plants in western regions, where wind and solar resources are desirable, but also the main regulating method of the grid for system inertia support, emergency power support, voltage regulation, etc., participating in the power ancillary service market independently or together with other regulating power sources.

Take the informatization, digitization and intelligence of the energy sector as accelerators to catalyse the modernization and transformation of the energy system

Big data, 5G, artificial intelligence, Internet of Things and other new technologies boost the informatization, digitization and intelligence of the energy sector. As technologies keep progressing and cost continues to reduce, leading companies and their intellectual resources will play a key role in improving the competitiveness in offshore wind power and distributed solar power industries. The expanding applications of smart grid, energy Internet, and energy storage, as well as a better distributed market-oriented power trading mode, will make the whole energy system become more efficient and convenient. The development of core cutting-edge technologies, such as new energy vehicles and new energy industries, will spread the new energy industry chain both upstream and downstream, effectively promoting the high-quality development of the energy sector.

It is important to improve the green smart grid planning. Grid planning needs to be coordinated with power supply construction and load development, balancing the large-amplitude and high-frequency fluctuations on supply and demand side. China aims to develop utility-scale and distributed energy in parallel and emphasize on both local and inter-regional clean energy consumption, thus optimizing the allocation of clean and low-carbon energy from a broader view. Power grid planning must be considered nationwide: from establishing a multi-layered national interconnection system from the intra-province balance at top-priority, to regional coordination, and to the broader national balancing dispatch. Intelligence technologies can efficiently assist grid operation and management, with the help of which the grid can better accept and configurate power from multiple energy sources and meet various requirements from supply and demand-side users.

Guide the continuous optimization of energy production with end-use energy and electricity demand, and continue to promote the realization of the carbon neutrality target

Electrification and green electricity substitution in end-use sectors can improve energy efficiency and reduce CO_2 emissions. Using green electricity substitution to boost the modernization and electrification in industry, transportation, building, and other end-use sectors is a practical path to improve the energy consumption structure and reduce pollution. There are several possible ways to achieve this plan: simultaneously promoting renewable energy production and electric vehicles; focusing on coal reduction and electrification in high-polluting industries, and in urban and rural commercial and residential buildings; expanding the capacity of urban and rural gas power and heat supply infrastructure and integrating it with distributed renewable energy. The goal of the energy revolution will be realised when every citizen can enjoy sustainable energy.

The active response on the demand side is another key element. China needs to improve the load-side response mode based on price incentives, formulate a pricing system that reflects the supply and demand of the market, improve and promote peak and valley pricing mechanisms on both the generation and user sides, and improve demand-side power management. China also needs to integrate system operating conditions, market transactions, and user consumption data into a comprehensive management system and use big data technologies to analyse the load-side data to enhance the load-side responsive capabilities. There are also strong practical needs for expanding the application of V2G, accelerating the construction of electric vehicle charging infrastructures, and innovating the interactive technology and business model of electric vehicle charging and discharging. Further, China should consider how to re-use retired batteries for storage and explore the potential to synchronize the life cycle of electric vehicle batteries with renewable energy generation.

Finally, hydrogen substitute through electrolysis has been put on the agenda. In the future, hydrogen produced through electrolysis will play a pivotal role in connecting all kinds of renewable energy. It is necessary to start constructing hydrogen-electricity infrastructures in suitable locations. China strives to make independent breakthroughs in hydrogen industry technologies such as green hydrogen production, long-distance hydrogen transportation and end-use applications. Hydrogen production through electrolysis will gradually become the major consuming method for wind and solar power in the western region. Due to the expected decline in the cost of green hydrogen, the downstream application market of hydrogen energy will spread from the transportation sector to the energy storage, industrial, and building sectors, forming an electric-hydrogen combining industry system.

Additional key findings from the Outlook research

Carbon pricing

Adding a cost for CO_2 emission (carbon pricing) is an important policy instrument in the overall climate policy framework. China launched a national carbon emissions trading system (ETS) in 2021 after a decade in the making. This market-based mechanism is supposed to provide incentives for low-carbon technology and drive emissions reduction, contributing to China's decarbonization pathway to 2060. In addition to the emissions trading system, other types of carbon pricing schemes such as carbon tax could similarly be introduced and play their roles in driving the transformation.

At the start, China national ETS adopts an intensity-based target, in contrast to the absolute emissions target in other Cap and trade schemes. Thermal power plants are given certain numbers of allowances based on a predetermined benchmark for their fuel type and capacity category (emissions intensity, in ton CO_2/MWh). Thus, ageing and inefficient thermal plants are punished if their emission intensity is above the benchmark since they need to buy allowances for compliance. On the contrary, more efficient thermal plants will have surplus allowances as subsidies, since they can sell in the carbon market and get revenue.

There is a limitation for an intensity-based target. Even though it can improve the overall efficiency of the thermal power fleet (mainly coal), it indeed provides incentives for building new and more efficient plants whose emission intensity are below the benchmark. Moreover, the ETS emissions will rise as long as total output (thermal power generation) increases. With China set to peak CO_2 emissions, it is necessary to bring the ETS target in line with the overall emissions target. This implies that national ETS shall quickly move to an absolute emissions reduction target in order to drive down emissions in the ETS-covered sectors, fulfilling the 2030 CO_2 peak goal. The government could define the contribution of the ETS into the overall climate target.

In addition to switching from an intensity-based target, national ETS shall also gradually introduce auctioning of allowances, and reduce the free allocation of allowances. The revenues from auctioned allowances could be used as funding for investments and innovation in low-carbon technology.

As carbon pricing provides incentives for renewables investments, it is valuable to ensure the consistency and synergy between carbon pricing and RE support policies.

Power to X in China

Power-to-X (PtX) encompasses numerous energy conversion pathways and a broad range of output fuels, energy forms, chemicals and even foods. In CETO, a comparative study investigates how the energy systems in two provinces could serve as a PtX production base. Qinghai is a province with considerable VRE resources and with large potential to deploy these at low cost. Guangdong is a load centre, industrial hub, aviation hub, and not least a key location for international shipping. Guangdong has hydrogen development included in its 14th FYP with a focus on "clean-energy-based" hydrogen production and chemical by-product hydrogen sources.

The analysis is carried out by integrating OptiFlow, an open source for representing networks of interconnected processes, with the EDO model representing the power and district heating supply in the CETO scenarios.

Key takeaways from the case studies

Even future PtX conversion pathways are likely to involve significant conversion losses along with an increased demand for electricity and heat. Therefore, to reduce CO_2 emissions, only decarbonised electricity should be used for PtX and it should not be utilised in sectors where direct electrification is economically feasible.

Different provinces require different solutions. In a comparison of two provinces:

- A provinces access to biogenic carbon, market for PtX products and power system characteristics are relevant for which PtX products should be prioritised.
- To reduce CO_2 emissions, large-scale PtX production should not take place in a province until it can be assured that the additional electricity demand is produced from CO_2 free sources.

In the future, PtX solutions can deliver an important tool in a decarbonising society. The above findings underscore the need for taking a system perspective in this decarbonisation effort, with PtX pathways being reserved for sectors that are the most difficult to electrify. Quantitative studies are required to guide 1) Where and when to build large scale PtX facilities, and 2) Prioritise and quantify the different PtX products based on the CO_2 intensity of the fuels replaced and economic feasibility.

Status for CCS and CCUS in China

As the world's largest energy consumer and carbon emitter, China has long recognized carbon capture, utilization, and storage's (CCUS) potential to allow the country to utilize fossil fuel while simultaneously achieving deep carbon emissions reductions. In the past decade, the Chinese central government released at least 26 CCUS-related policies, focusing on both technology R&D and industrial demonstrations. Against the backdrop of China's climate pledge of peaking carbon dioxide emissions before 2030 and achieving carbon neutrality before 2060, CCUS policies in China become increasingly proactive and supportive.

The overall mitigation impact of CCUS in China has been limited so far, despite the technology in carbon capture and breakthroughs in geological utilization. Between 2007 and 2019, China reached a cumulative carbon dioxide (CO_2) storage volume of 2 million tons (Mt).

Unlike other net-zero emissions technologies such as energy conservation, renewables-based electrification, bioenergy, green hydrogen, and enhancement of biological sinks, the Achilles' heel of CCS deployment is the lack of auxiliary benefits other than carbon emissions abatement, which makes it difficult to take decisions in near-term actions. It is crucial that CCUS development does not lead to a noticeable reduction of nationwide efforts to support energy conservation, renewable and other clean energy development, both in R&D and financial terms. In absence of major technological breakthrough, CCUS should be positioned as the "last resort" backup technology to decarbonize hard-to-abate sectors where no viable alternative is available.

China should aim: 1) to further improve quality of energy and emissions statistical reporting; 2) to establish supportive and comprehensive CCUS regulations and standards; 3) to eliminate all fossil fuel subsidies to stimulate market penetration of net-zero emissions technologies including CCUS in the domestic front; 4) to proactively work with the EU and other like-minded countries with net-zero emission targets to explore a multilateral instead of unilateral solution for carbon leakage protection in the international front.

Part 1: Energy Transformation Status

1 The global quest for carbon neutrality

1.1 Key messages

- In August, Working Group 1 of the Intergovernmental Panel on Climate Change (IPCC) released its Sixth Assessment Report (AR6). The IPCC working group finds it is "unequivocal that human influence has warmed the atmosphere, ocean and land." [3]
- The IPCC also finds that the scale of recent changes in the climate is "unprecedented over many centuries to many thousands of years" and that "human-induced climate change is already affecting many weather and climate extremes in every region across the globe."
- Global roadmaps by the IEA and IRENA show pathways for reducing energy sector emissions 40-45% by 2030 and achieving net-zero emissions from the energy sector by 2050. The two studies show that achieving net-zero emissions is possible but only if global emissions are immediately reduced.
- In the past several years, most countries (including the United States, Japan, South Korea, United Kingdom, Canada, and Australia) as well as the European Union have committed to achieve net-zero greenhouse gas emissions by 2050. At the COP 26 meeting in Glasgow in November 2021 China and the United States launched a joint declaration on enhancing climate action in the 2020s with specific short-term cooperation actions on measures to reduce greenhouse gas emissions aimed at keeping the Paris Agreement-aligned temperature limit within reach.

1.2 We are in a climate crisis, and it will be worse in the future unless we see immediate action

The IPCC is currently producing its Sixth Assessment Report (AR6). The AR6 consists of reports from each of its three working groups, a Synthesis Report, three Special Reports, and refinement to its latest Methodology Report. The AR6 is commissioned by 195 national governments commission the reports. The Summary for Policymakers is agreed upon line-by-line by representatives every government.

On 6 August 2021, Working Group 1 of the IPCC published its report, which examines the physical science underpinning past, present and future climate change.[4]

The IPCC's findings include the following:

- It is **"unequivocal"** that human influence has warmed the atmosphere, ocean and land."
- The scale of recent changes in the climate is "unprecedented over many centuries to many thousands of years."

- "Human-induced climate change is already affecting many weather and climate extremes in every region across the globe."
- Since the preindustrial period, the average global temperature has risen by around 1.09°C [0.95-1.20°C].
- Glaciers are retreating globally at a rate which has not been seen in the past 2000 years. Oceans are heating up at a rate similar to the one at the most recent ice age 11000 years ago.

Future climate scenarios

The IPCC describes five emissions pathways with very low to very high CO_2 emissions, each with different years of CO_2 peak and CO_2 doubling or halving for high and low or medium scenarios. The IPCC also provides an updated assessment of climate sensitivity - that is, how much temperatures change in response to increases in atmospheric carbon dioxide concentrations.

In the high and very high emissions scenarios, global CO_2 emissions double by 2100 and 2050, respectively, leading to temperature rises around 3-4°C. In such a climate, droughts that occurred once in a decade are now more than five times more likely to occur, tropical cyclones are 30% more likely, and sea levels rise by 12-16 metres over the next 2000 years. At the current +1.1°C, we are already experiencing some of these effects but only to a smaller extent as the severe droughts are 2.4 times more frequent, extreme precipitation events are 1.5 times more frequent.

In the IPCC's moderate emissions scenario, CO_2 emissions peak mid-century and are halved by the end of the century. This scenario leads to a temperature rise of 2.1-3.5°C and hence exceeds the 2°C target of the Paris Agreement[5]. To be aligned with the Paris Agreement, the global emissions pathway need to follow the low or very low scenario. In the low scenario, temperatures exceed 1.5°C and only in the very low scenario with significant net CO_2 removal can 1.5°C be achieved around 2070 with some overshoot mid-century. In both scenarios, emissions are immediately reduced so that by 2030 global emissions are reduced by around 5-10Gt (based on Figure SPM.4).

Risk of irreversible tipping points

In addition to the scenarios, the report also draws attention to tipping points. While most events so far are consistent with a linear response to increasing atmospheric greenhouse gas concentrations, non-linear responses are possible. "Tipping points", where a climate system changes abruptly once it passes a threshold, could be irreversible. Even if atmospheric carbon concentration returned to the pre-threshold state, the system would not reverse to its previous climate state. Such changes could include disruption of the Atlantic Meridional Overturning Circulation, loss of the Greenland and West Antarctic Ice sheets and collapse of ecosystems such as the Amazon.

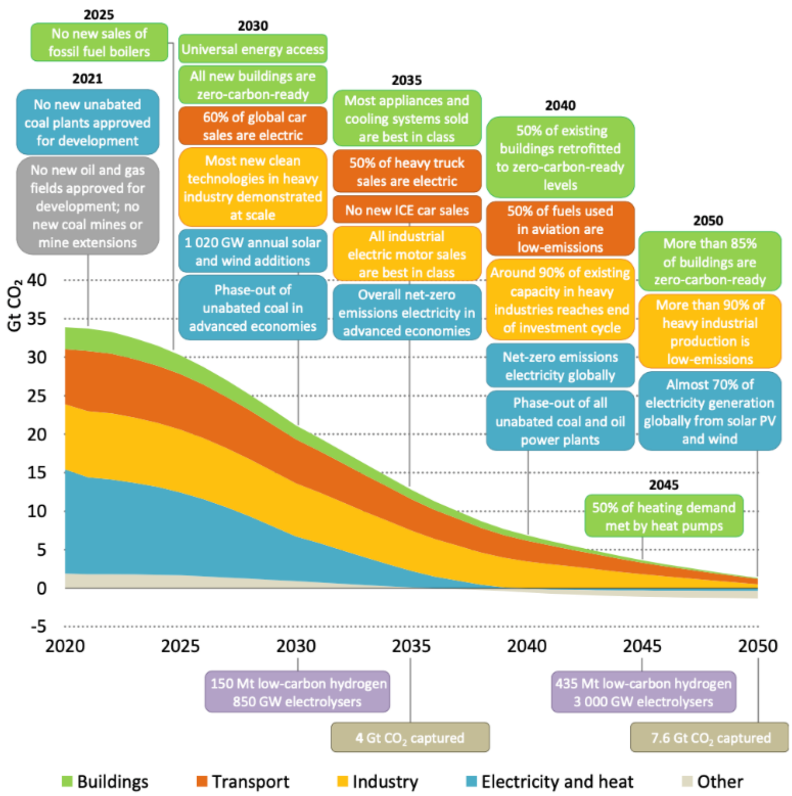
The AR6 finds that human activities have now altered the global climate to one never experienced by any human civilisation.

1.3 IEA and IRENA report on net-zero pathways for the energy sector

In the past years, several international organisations have published studies exploring possible global energy sector pathways to reach net-zero by 2050. The following provides highlights from IEA's *Net-Zero by 2050 - A Roadmap for the Global Energy Sector* and IRENA's *World Energy Transitions Outlook: 1.5°C Pathway*[6].

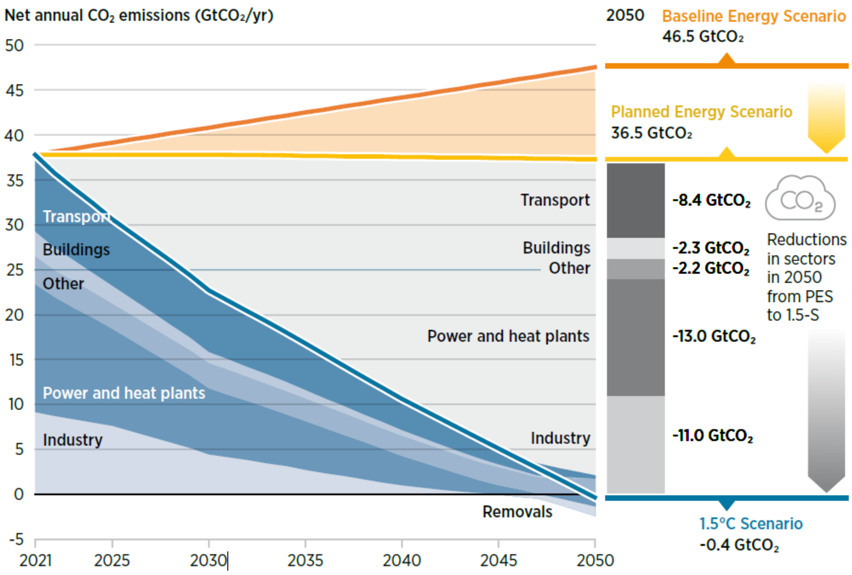
Both studies deem their pathways aligned with limiting temperatures to 1.5°C by using the carbon budget of around 500Gt from SRP1.5 with a 50% likelihood and according to IEA's report "Assuming parallel action to address CO2 emissions from agriculture, forestry and other land use (AFOLU)".

Figure 1-1: Global emissions trajectory with milestones to achieve net-zero emissions in the energy sector from the *Net-Zero by 2050 -A Roadmap for the Global Energy Sector* by the IEA[7]



The two studies show that achieving net-zero emissions is possible but only if global emissions are immediately reduced. To reach net-zero by 2050, IEA proposes a pathway where emissions are cut by around 40% by 2030, while IRENA aims for a 45% reduction in line with the IPCC recommendations. For comparison, the two carbon reduction pathways are shown in Figure 1-1 and Figure 1-2.

Figure 1-2: Global emissions trajectory to net-zero emissions in the energy sector from the *World Energy Transitions Outlook: 1.5°C Pathway* by IRENA[8]



They build on the consensus that the two key elements are a rapid expansion of renewable power generation and deep direct and indirect electrification of several sectors. By 2050, in both net-zero scenarios, the renewable share in power generation is around 90%, while IRENA deploys a larger share of renewable in primary energy share, 74%, versus IEA's 67%. In both studies, around 50% of the final energy demand is electrified. They both heavily rely on carbon capture technologies, such as CCS, CCUS and CDR technologies on a large scale, i.e. in Gt per year, and bioenergy to achieve net-zero emissions.

As shown in Figure 1-1, the IEA's roadmap provides clear milestones needed to realise net-zero by 2050. The report is essential since IEA previously only has provided their sustainable development scenario, which reached net-zero by 2070.

The key elements of the road map are:

- Rapid and deep decarbonisation of the power sector ensuring that renewables generate 88% of the electricity by 2050. The decarbonisation includes a tripled VRE share by 2030, by building 630 GW of solar PV and 390 GW wind annually by 2030. It also means that there should be no new investment in any fossil fuel sources to avoid stranded assets.
- Deep electrification of transport, buildings, and industries. In particular, the deep electrification of the industry sector means that global electricity demand more than doubles between 2020 and 2050. This growth rate is around double the overall rate of growth in final energy consumption.

- Massive deployment of CCS to meet the net-zero target. The roadmap assumes that CO2 captured will increase 190 times from the current 0.04Gt to 7.6Gt annually by 2050, primarily to outbalance energy-related and process emissions from the industry sector.
- Biomass playing a critical role by providing 102 EJ by 2050. However, this requires a large, dedicated land-area which might conflict with land use for other purposes such as food production or opportunities for storing carbon[9].

1.4 Regional and National quests for carbon neutrality

Carbon neutrality commitments

In the past several years, most countries (including the United States, Japan, South Korea, United Kingdom, Canada, and Australia) and the European Union have committed to achieving net-zero greenhouse gas emissions by 2050.

Table 1-1: National 2030 targets and year for net-zero of selected countries

	Intermediate emission reduction target (2030 refer to NDC targets)	Year of net-zero	Base year	Target form
European Union	Min. 55% by 2030	2050	1990	Legally binding since 2021
Denmark	70% by 2030	2050	1990	Legally binding since 2020
Germany	65% by 2030	2050	1990	Legally binding since 2021
USA	50-52% by 2030	2050	2005	Policies
China	Peak by 2030	2060	-	Policies*

**legislation are being revised in China to reflect the targets*

EU

With the *European Green Deal*[10], which was published in December 2019, the European Union has pledged its commitment against the climate crisis. Specifically, the clean energy transition presented in the *European Green Deal* focuses on 3 key principles:

- ensuring a secure and affordable EU energy supply
- developing a fully integrated, interconnected, and digitalised EU energy market
- prioritising energy efficiency, improving the energy performance of buildings and developing a power sector based largely on renewable sources

The EU aims at a reaching climate-neutrality by 2050 and to further reduce net greenhouse gas emissions by at least 55% by 2030 compared to 1990 levels, as presented in the *2030 Climate Target Plan*[11]. The *European Climate Law*[12] – in force since 29 July 2021 – sets these targets into EU law and binds EU Institutions and the Member States to take the necessary measures at EU and national level to meet these targets. In addition, the Climate Law includes:

- recognition of the need to enhance the EU's carbon sink through a more ambitious land use, land use change and forestry (LULUCF) regulation,
- a process for setting a 2040 climate target,
- a commitment to negative emissions after 2050,
- measures to keep track of progress and adjust actions accordingly.

The progress will be reviewed every five years, in line with the global stocktake exercise under the Paris Agreement.

Moreover, to ensure that EU policies are in line with the agreed climate goals, the EU Commission, on 14 July 2021, has presented the *Fit for 55 package*[13]. It consists of a set of proposal to revise and update EU climate, energy, and transport-related legislation. It includes, among other initiatives, to revise:

- the EU emissions trading system (EU ETS), including its extension to shipping, revision of the rules for aviation emissions and establishing a separate emission trading system for road transport and buildings
- the effort sharing regulation on member states' reduction targets in sectors outside the EU ETS
- the regulation on the inclusion of greenhouse gas emissions and removals from land use, land use change and forestry (LULUCF).

Another initiative under the EU Green Deal is the new Carbon Border Adjustment Mechanism[14] (CBAM) which will put a carbon price on imports of a targeted selection of products. The EU states that the aim is to ensure that European emission reductions contribute to a global emission decline, instead of pushing carbon-intensive production outside Europe. In its first phase, the CBAM will focus on goods most a risk of carbon leakage[2] as cement, iron, steel, aluminum, fertiliser, and electricity. The CBAM is expecting to be first introduced in a transitional phase until it's fully in place in 2026.

The *European Green Deal* doesn't focus only on energy and emissions but aims to embarking everyone on the green transition. This is the target of the *European Climate Pact*[15] which invites people, communities, and organisations to participate in climate action and build a greener Europe. The Pact will prioritise actions focused on four areas that provide benefit to the climate and the environment as well as the health and

[2] Carbon leakage occurs when industries transfer polluting production to other countries with less stringent climate policies, or when EU products are replaced by more carbon-intensive imports.

wellbeing of citizens. These are: Green areas, Green transport, Green buildings and Green skills.

Denmark

In 2020, the Danish national Government enacted a Climate Act, which sets legally binding targets to reduce GHG emissions by 70% in 2030 relative to 1990 levels and to reach net-zero no later than 2050, as shown in Table 1-1.

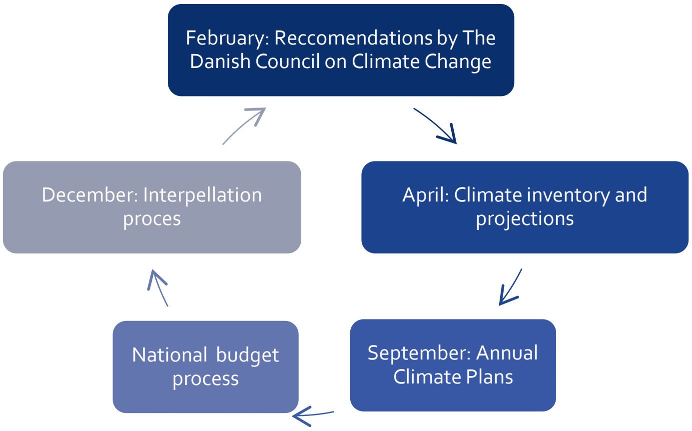
A key component of the Climate Act was giving the Danish Council on Climate Change a central role in advising and assessing the Danish Government on pathways to net-zero by 2050[16]. The role includes proposing intermediate reduction targets such as 50-54% by 2025. Similar to the Committee on Climate Change in the UK, the Danish Council on Climate Change is an independent body with the following four main tasks[17]

- evaluate the status of Denmark's implementation of national climate objectives and international climate commitments,
- analyse potential means of transitioning to a low-carbon society by 2050 and identify possible measures to achieve greenhouse gas reductions,
- draw up recommendations to help shape climate policy, including a selection of potential mechanisms and transition scenarios,
- contribute to the public debate. The Danish Council on Climate Change must, to the extent required in the preparation of its analyses and other work, consult and involve relevant parties, including, among other business interests, social partners in the labour market and civil society.

According to the Climate Act, the Government must follow a cycle of setting legally binding intermediate targets every fifth year. Like the UK, these are set far in advance, in this case, ten years before the target, to allow enough time to develop suitable supporting policies.

It also follows a yearly cycle, as shown in Figure 1-3, which has been specified in the climate act. In this, based on recommendations from the climate council, the Danish Government will each year develop and present Climate Action Plans which should outline concrete policies to reduce emissions for all sectors: energy, housing, industry, transportation, energy efficiency, agriculture, and land use change and forestry.

Figure 1-3: Annual cycles of climate action plans



Currently, reductions until 2030 are driven primarily by the power sector, which is set to be 100% fossil-free by 2030. The energy sector has been assigned to at least 55 % renewables energy in total final consumption.

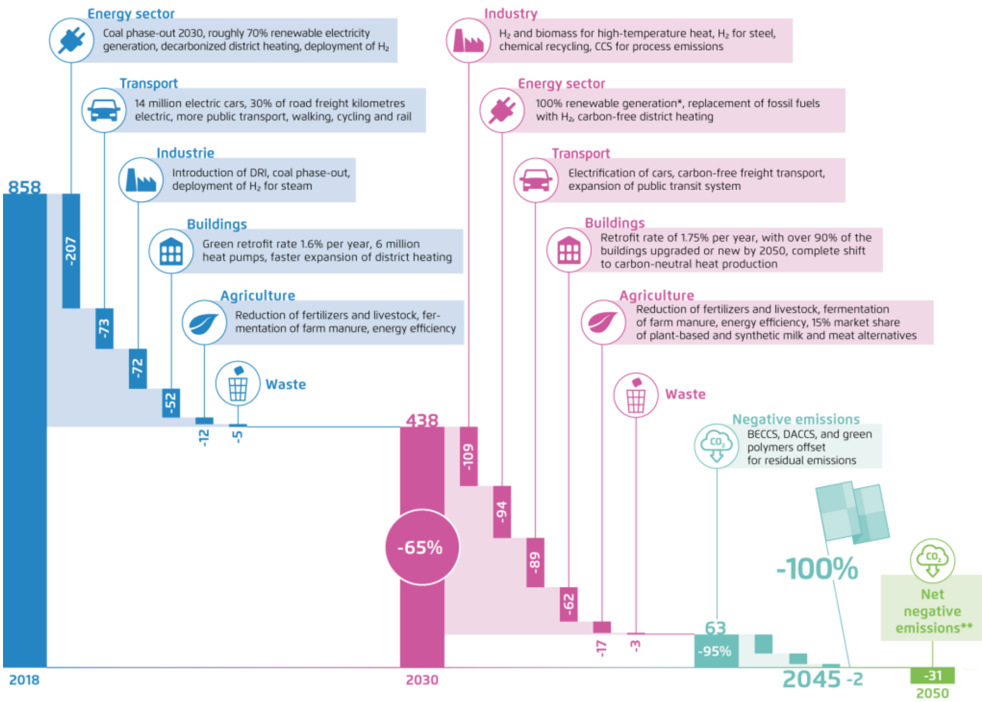
To support the policy process, the Danish Energy Agency has changed its energy outlook to "Denmark's Energy and Climate Outlook" to include emissions projection under frozen policies. Thereby, the outlook report helps to examine the extent to which Denmark's climate and energy targets and commitments will be met within the current regulatory framework. The Danish Energy Agency also provides technical reduction potentials of different solutions for the government to use as a basis for designing the path towards net-zero.

Germany

The German Climate Change Act ("Klimaschutzgesetz" - KSG), which has been in force since the end of 2019, sets legally binding climate targets for the first time, mandating greenhouse gas emissions reduction of 55 % compared to 1990. However, climate targets after 2030 were dropped during the legislative process. In a decision published in May 2021, the German Federal Constitutional Court held that the Climate Change Act is partly unconstitutional, as Germany’s stated climate targets were too week and put future generations at danger. Consequently, in June 2021, Germany adopted an amendment to its Climate Change Act and a climate and energy package, together with a Euro 8 billion emergency programme for climate mitigation measures mainly in the buildings and industry sectors. The amended Act includes the target of a 65% national emissions reduction below 1990 levels by 2030 (up from 55%) and moves Germany’s climate neutrality target forward five years to 2045.

To investigate how accelerated climate actions could allow Germany to comply with the ruling of the Federal Constitutional Court, three German think tanks including Stiftung Klimaneutralität, Agora Energiewende and Agora Verkehrswende commissioned an indepth modelling study and presented a clear pathway to reach a climate neutral Germany in three steps and six strategies, which also supports the provisions of the EU Climate Law[18].

Figure 1-4: In three steps and six strategies towards climate neutral Germany by 2045



More specifically, reducing greenhouse gas emissions by 65 per cent in relation to 1990 is an ambitious but achievable interim target for 2030 on Germany's path to climate neutrality. Starting from 2030, only carbon-free investment should be made across the German energy economy, leading to a 95% greenhouse gas emissions reduction without negative emissions by 2045. Finally, the remaining 5% residual emissions could be compensated with negative emissions technologies including Bioenergy with Carbon Capture and Storage (BECCS), Direct Air Capture (DAC), and green polymers among others.

The main milestones are higher climate targets of 65 percent lower emissions by 2030, 77 percent by 2035 and 90 percent by 2040. Likewise, climate technologies such as energy efficiency, renewables, electrification, and hydrogen must be ramped up much faster. According to the report, climate neutrality by 2045 creates a renewable market of around 30 gigawatts per year in Germany alone, along with a building renovation rate of 1.75 percent annually and a rapid ramp-up of hydrogen technology. The study clearly indicates that the right course must be set today if the transition to climate neutrality is to succeed in all sectors in the decades to come.

United States

Under President Joe Biden, the United States has adopted its most ambitious climate change goals ever. In April 2020, President Biden announced that the United States would reduce its emissions by 50-52% from 2005 levels by 2030. President Biden also set a goal of reaching zero carbon emissions from the US power sector by 2035.

The goals are being pursued through several policies. President Biden uses his authority under existing laws to set standards for carbon dioxide emissions from power plants and vehicles – the two most important sources of greenhouse gases in the United States. He is accelerating the development of renewable energy on US public lands. He has released a rule to reduce the use of HFCs (a super-polluting global warming gas) by 85% in 15 years.

In addition, the US Congress is currently considering several measures to address climate change. This includes tax credits for solar power, wind power, electric vehicles, carbon capture and low-carbon hydrogen production.

In addition, state governments play an essential role in climate change in the United States. The California and New York governments have been especially ambitious in adopting climate change policies. California has a legally binding emissions trading program and sets its own vehicle fuel efficiency standards. New York State has ambitious goals for renewable energy deployment in the years ahead. Many other state governments have policies to promote renewable energy and speed deployment of clean energy.

China

In 2014, President Xi Jinping announced that Chinese emissions of carbon dioxide would peak by 2030. In 2017, the 19th National Congress introduced the new roadmap, to build a clean, low-carbon, safe and efficient energy system. In September 2020, in a speech to the UN General Assembly, President Xi announced that China would achieve carbon neutrality by 2060. These two headline goals – known as the "30-60 goals" – shape the Chinese climate change policy.

President Xi has announced other important climate change goals as well. In a speech to the Climate Ambition Summit in December 2020, President Xi announced that by 2030 China will:

- lower its carbon dioxide emissions per unit of GDP by over 65 per cent from the 2005 level
- increase the share of non-fossil fuels in primary energy consumption to around 25 per cent
- expand the forest stock volume by 6 billion cubic meters from the 2005 level, and
- bring its total installed capacity of wind and solar power to over 1200GW.

The Chinese government uses several tools to help achieve its climate change goals. Some elements of these tools include:

- support for solar and wind power with renewable power purchase requirements and other policies
- support for natural gas infrastructure development to help reduce coal use in industry and space heating
- vehicle fuel efficiency standards
- supporting measures for the manufacture and purchase of new energy vehicles (NEV)
- energy efficiency standards for industries and appliances
- CO_2 emissions standards for coal power plants
- a CO_2 emissions national trading program, starting in the power sector.

In September 2021, President Xi announced that China would stop building coal power plants abroad.

On 15 September 2021, China's ratification of the Kigali Amendment to the Montreal Protocol went into effect, which aims to gradually reduce the consumption and production of hydrofluorocarbons, or HFCs.

On 24 October 2021, China released a document titled "Working Guidance For Carbon Dioxide Peaking And Carbon Neutrality In Full And Faithful Implementation Of The New Development Philosophy" [19], which lays out key specific targets and measures for upcoming decades. The guideline is the overarching document of China's "1+N" policy framework for CO_2 emissions peaking and carbon neutrality, and will, together with the "Action Plan for Carbon Dioxide Peaking Before 2030[20]" that was released on 26 October, constitute the top-level design to help accomplish the carbon goals.

1.5 U.S.-China Joint Glasgow Declaration on Enhancing Climate Action in the 2020s

At the COP26 meeting in Glasgow in November 2021, China and the United States launched a joint declaration on enhancing climate actions in the 202s.

In the declaration, the two sides intend to cooperate on regulatory frameworks and environmental standards related to reducing emissions of greenhouse gases in the 2020s, maximizing the societal benefits of the clean energy transition, policies to encourage decarbonization and electrification of end-use sectors, key areas related to the circular economy, such as green design and renewable resource utilization, and deployment and application of technology such as CCUS and direct air capture.

The two countries intend to cooperate to enhance the measurement of methane emissions; to exchange information on their respective policies and programs for strengthening management and control of methane; and to foster joint research into methane emission reduction challenges and solutions.

The United States and China intend to develop additional measures to enhance methane emission control, at both the national and sub-national levels before COP27. They intend to convene a meeting in the first half of 2022 to focus on the specifics of enhancing measurement and mitigation of methane, including through standards to reduce methane from the fossil and waste sectors, as well as incentives and programs to reduce methane from the agricultural sector.

In order to reduce CO_2 emissions the two countries intend to cooperate on policies that support the effective integration of high shares of low-cost intermittent renewable energy, transmission policies that encourage efficient balancing of electricity supply and demand across broad geographies distributed generation policies that encourage integration of solar, storage, and other clean power solutions closer to electricity users, and energy efficiency policies and standards to reduce electricity waste.

The two sides intend to engage collaboratively in support of eliminating global illegal deforestation through effectively enforcing their respective laws on banning illegal imports.

The two sides intend to establish a "Working Group on Enhancing Climate Action in the 2020s," which will meet regularly to address the climate crisis and advance the multilateral process, focusing on enhancing concrete actions in this decade. This may include, inter alia, continued policy and technical exchanges, identification of programs and projects in areas of mutual interest, meetings of governmental and non-governmental experts, facilitating participation by local governments, enterprises, think tanks, academics, and other experts, exchanging updates on their respective national efforts, considering the need for additional efforts, and reviewing the implementation of the Joint Statement Addressing the Climate Crisis of April 2021 and this Joint Declaration.

2 The Chinese energy system today

2.1 Key messages

- The primary energy consumption mix becomes more cleaner, the share of non-fossil fuel exceeds the 15% target of the 13th FYP. Although coal remains the dominant energy source in China, its share declined by 11.5% in the past decade.
- As China enters a new phase in the economic development, the share of industry in energy consumption continues to decrease, while the residential sector shows the biggest consumption increase among all end-use sectors.
- Reliance of natural gas and oil imports further increases, making energy security a key concern in the energy reform process.
- Driven by the reduction in the share of coal consumption and electrification, the cumulative reduction of CO2 emission/GDP reached 18% in the 13th FYP period. More than 120 GW of outdated coal-fired units have been phased out and most of existing units have had ultra-low emission and energy saving retrofit.
- Since 2010, China's energy consumption intensity has dropped by 28.7%, making China one of the countries with the fastest reduction in energy consumption intensity in the world.
- China is still the largest renewable energy investment market, and the total installed wind power and solar PV capacity reached 281 GW and 253 GW respectively in 2020.
- The government strives to facilitate solar PV poverty alleviation program. By the end of 2020, half of poverty-stricken villages have installed poverty alleviation PV plants, which creates an average annual revenue of RMB 200,000 per village.

2.2 Overview of energy consumption

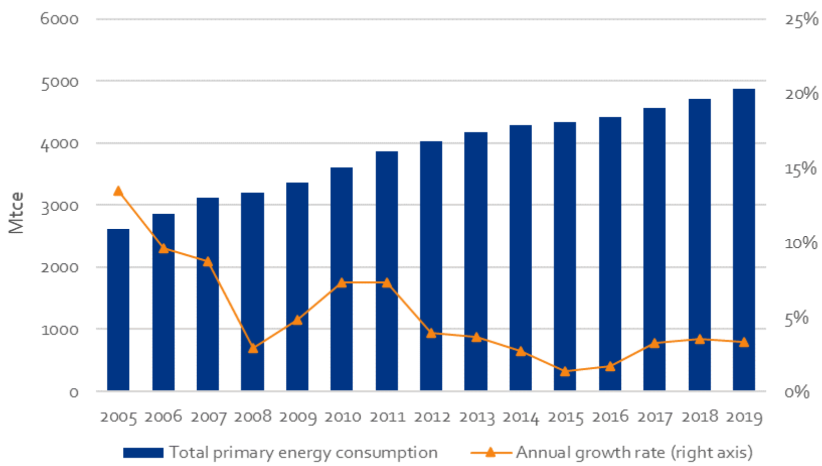
Statistical method of primary energy terms

In *China Energy Transformation Outlook 2022* (CETO 2022), the statistics adopted is mainly based on the National Bureau of Statistics (NBS), supplemented by the information collected for the CETO modelling database. NBS adopts the coal substitution method — the traditionally used approach to account for the primary energy content in China. The coal substitution method implies that the electricity production from wind and solar power plants as well as nuclear power plants is transformed to an equivalent coal consumption in an average coal-fired power plant.

Economic growth decoupling from total primary energy consumption increase

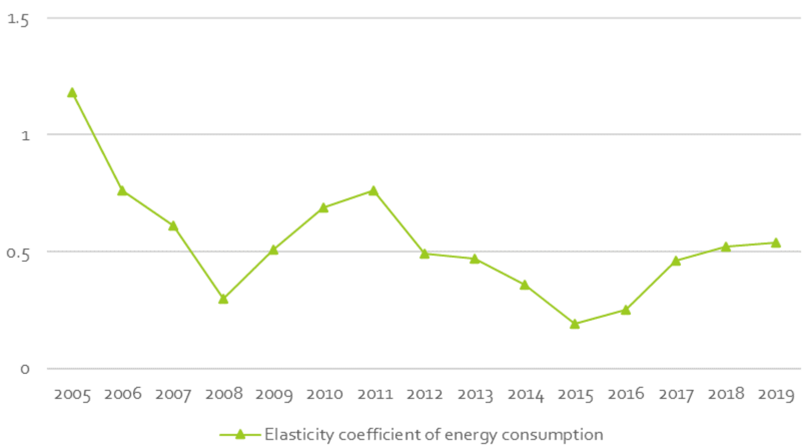
According to latest data of the *China Energy Statistical Yearbook 2020* released by the National Bureau of Statistics (NBS)[21], China's total primary energy consumption (TPEC) from 2006 to 2019 demonstrates a characteristic of year-on-year increases amid a slowdown in the fluctuations of growth rate and a continuous optimization of the structure. The average annual growth rate of TPEC was 2.8% during the 12th Five-Year Plan (FYP) period (2011-2015), and 2.9% in the first four years of the 13th FYP period (2016-2019), roughly on par with that of the 12th FYP, indicating a low growth prospect for energy consumption. As of 2019, TPEC was 4875 Mtce. Compared with a GDP growth of 6.1%, TPEC only increased by 3.2% year-on-year. As China achieved a medium-to-high growth of the economy with a lower growth of energy consumption, the country's energy elasticity (growth in energy consumption relative to growth in GDP) remains at a low level of 0.52.

Figure 2-1: Energy consumption and growth in China from 2005 to 2019



Source: National Bureau of Statistics (NBS), accessed in October 2021

Figure 2-2: Elasticity coefficient of energy consumption in China from 2005 to 2019

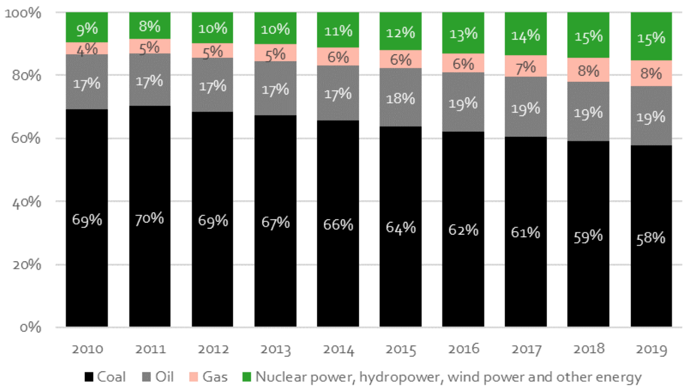


Source: NBS, accessed in October 2021

China enters a new phase in the economic development, changing the energy consumption structure

China is currently entering a new phase of economic development, or a "new normal", accelerating economic transformation and deepening structural adjustment. In combination with the efforts to reduce fighting against air pollution, China's energy consumption structure is gradually moving towards clean energy. Although energy consumption is still dominated by coal, its share declines, with coal accounting for 57.7% of energy consumption in 2019, down 11.5 and 6.1 percentage points (pp), respectively, compared with the 2010 and 2015 figures. The share of oil consumption is gradually stabilizing, accounting for 18.9% of total energy consumption in 2019, slightly higher by 1.5 and 0.5 percentage points, respectively, compared with the 2010 and 2015 figures. The share of natural gas, and nuclear power, hydropower, wind power and other clean energy consumption has risen substantially, accounting for 23.4% in 2019, a significant increase of 10 and 5.6 percentage points, respectively, compared with the 2010 and 2015 figures. Of all energy sources, the share of non-fossil fuel in primary energy consumption has increased to 15.3% in 2019, reaching the 2020 target of 15% in advance.

Figure 2-3: China's primary energy consumption mix from 2010 to 2019 based on the coal consumption method

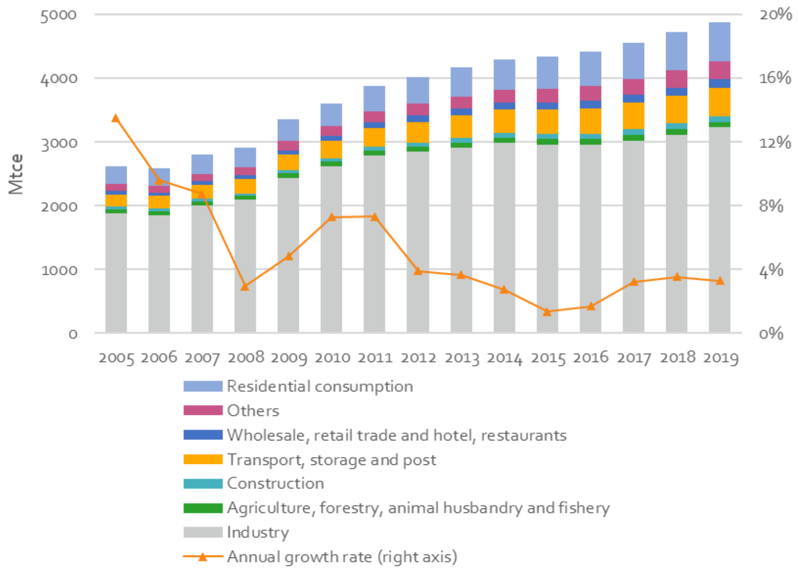


Source: NBS, accessed in October 2021

Industry is the big player in the total final energy consumption

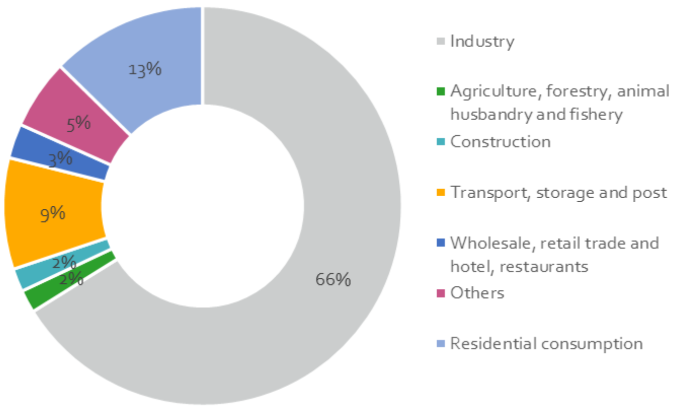
From the perspective of total final energy consumption (TFEC) by sector, industry is the largest energy-consuming sector. In 2019, China's industrial energy consumption accounted for 66.2% of total final energy consumption, followed by residential consumption (12.7%) and transportation (9.0%). The aggregation of wholesale, retail trade, hotel and restaurant, and other industries (8.5%) was in the fourth place. Agriculture, forestry, animal husbandry and fishery (1.8%) and construction (1.9%) made up relatively small shares in final energy consumption.

Figure 2-4: The final energy consumption by sector in China from 2005 to 2019



Source: NBS, accessed in October 2021

Figure 2-5: Total final energy consumption mix in China in 2019



Source: NBS, accessed in October 2021

Industrial structure optimization and living standards improvement results in changing the energy consumption structure

Since 2010, the share of energy consumption in industry sector has continued to decline. In 2019, its share declined by about 6.3 and 2.0 percentage points, respectively, compared with the 2010 and 2015 figures; on the other hand, the shares of energy consumption in the construction, transportation, wholesale and retail, other industries, and residents have all shown increases in varied degrees, among which the shares of energy consumption in residential and other industries increased most significantly. In 2019, the shares of energy consumption in these two sectors increased by 2.5 and 1.5 percentage points, respectively, compared with their 2010 figures, and by 1.0 and 0.6 percentage points, respectively, compared with their 2015 figures.

Table 2-1: Total final energy consumption by sector in China from 2010 to 2019

Year	Industry	Agriculture, forestry, and fisheries	Constru-ction	Transportation	Wholesale and retail	Other industries	Residential
2010	72.5%	2.0%	1.5%	7.5%	2.2%	4.2%	10.1%
2011	71.8%	2.0%	1.6%	7.7%	2.4%	4.4%	10.2%
2012	70.8%	1.9%	1.6%	8.1%	2.5%	4.6%	10.5%
2013	69.8%	1.9%	1.7%	8.4%	2.5%	4.7%	10.9%
2014	69.7%	1.9%	1.7%	8.5%	2.5%	4.7%	11.0%
2015	68.2%	1.9%	1.7%	8.9%	2.6%	5.1%	11.6%
2016	67.0%	1.9%	1.8%	9.0%	2.7%	5.3%	12.3%
2017	66.3%	2.0%	1.8%	9.2%	2.7%	5.3%	12.6%
2018	65.9%	1.9%	1.8%	9.2%	2.8%	5.6%	12.8%
2019	66.2%	1.8%	1.9%	9.0%	2.8%	5.7%	12.7%
2019 v.s. 2010	-6.3pp	-0.2pp	0.3pp	1.5pp	0.6pp	1.5pp	2.5pp
2019 v.s. 2015	-2.0pp	-0.1pp	0.1pp	0.1pp	0.2pp	0.6pp	1.0pp

Source: NBS, accessed in October 2021

Textbox 2-1: Explanation of the end-use sector classification in CETO 2022

As shown in the table above, the end-use sectors in China are classified into seven categories according to the National Economic Industrial Classification method. While the international organizations such as the International Energy Agency (IEA) and the Organization for Economic Co-operation and Development (OECD) adopt a five-category classification method, which is used in the CETO. Therefore, the seven categories are re-classified in order to carry out CETO analysis.

- The energy consumption of Agriculture, Forestry, Animal Husbandry and Fishery sectors is re-classified as Agriculture in CETO
- The energy consumption of Industry remains as Industry in CETO
- The energy consumption of Construction sector remains as Construction in CETO
- The energy consumption of Transportation sector remains as Transportation in CETO;
- The energy consumption of Wholesale and Retail Trade, Other industries, and Residential Consumption is split into Transportation and Building in CETO

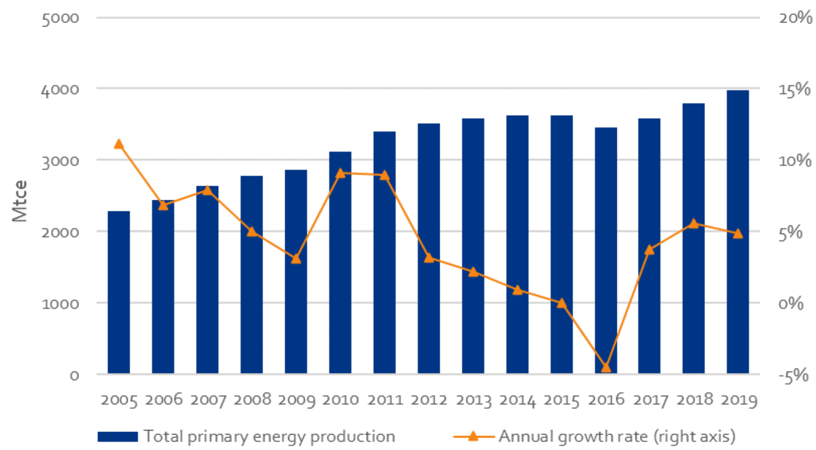
In addition, as the energy consumption data published by the NBS does not include residential heating (i.e. district heating and central heating), CETO adds certain amount of heat energy into Building sector based on the Statistical Yearbook of Urban and Rural Construction published by the Ministry of Housing and Urban-Rural Development (MoHURD).

2.3 Overview of primary energy production

Total primary energy production fluctuates to increase but the growth rate gradually slows down

From 2006 to 2019, China's total primary energy production (TPEP) showed an upward trend, albeit in slight fluctuations. As of 2019, China's TPEP reached 3973 Mtce at an average growth rate of 2.7% from 2010 to 2019, including of 3.0% during the 12th FYP period, and of 2.4% in the first four years of the 13th FYP period.

Figure 2-6: Total primary energy production in China from 2005 to 2019

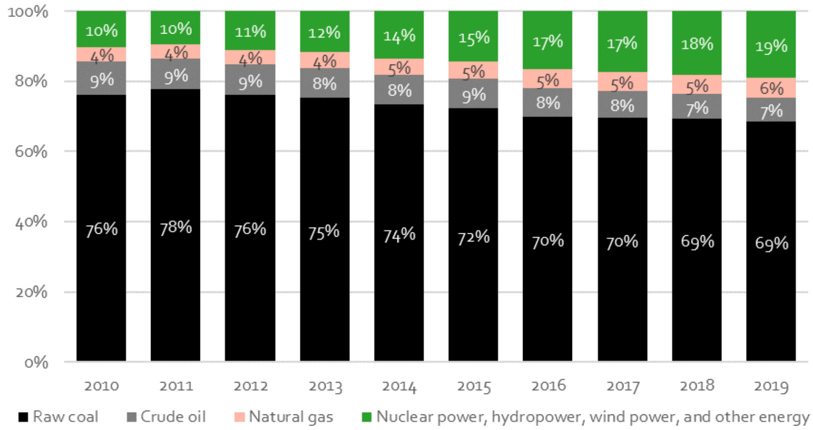


Source: NBS, accessed in October 2021

Share of coal production declines every year, continues to improve the primary energy production structure

China now has a relatively complete energy production and supply system in place, which covers a wide array of mature energy categories such as coal, electricity, oil, natural gas, new and renewable energy. Among them, raw coal, which takes up the highest share, accounted for about 68.6% of TPEP in 2019, followed by nuclear power, hydropower and wind power, which together accounted for 18.8% of TPEP; crude oil production accounted for about 6.9% of TPEP; and natural gas production took up the least share, accounting for only 5.7% of TPEP. Since the 12th FYP period, the share of clean energy production has steadily increased in China, and the structure of energy production witnessed continuous improvement.

Figure 2-7: Total primary energy production by fuel in China from 2010 to 2019



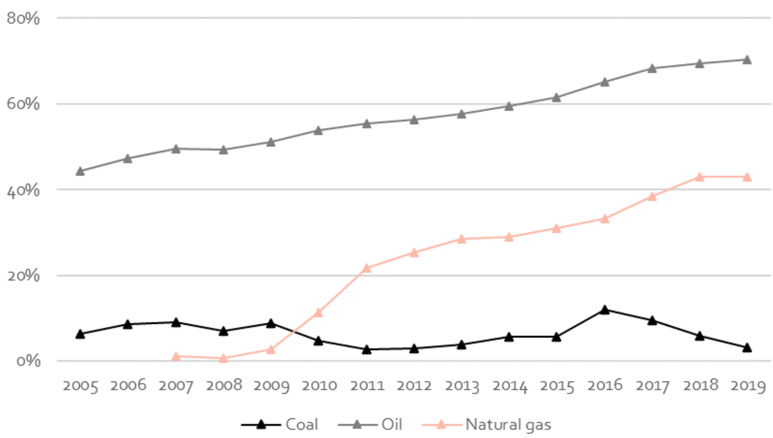
Source: NBS, accessed in October 2021

2.4 Overview of energy balance

The dependence on imported fossil fuels still keeps at high proportion

With China's growing economy and population, energy consumption and demand continue to increase. However, due to limited domestic energy supply capacity, China has shifted from a net exporter to a net importer of energy, with coal, oil and natural gas all requiring to be imported from abroad. Currently, China's overall dependence on foreign fossil energy is still high, with the dependence on foreign crude oil climbing to 70.4% and natural gas to 42.9%, but that on foreign coal dropping to 3.2% as of 2019. Energy security and guarantee of energy supply will continue to be one of the key concerns of energy development and reform over the long term.

Figure 2-8: China's external dependence on coal, oil and natural gas from 2005 to 2019



Source: Calculations based on data from NBS, accessed in October 2021

2.5 Overview of energy transition

Accelerating low carbon transition in the energy sector

Energy activities account for about 80% of the total GHG emissions in China. China attaches great importance to addressing climate change through firmly promoting low-carbon energy development. In recent years, China has speeded up the low-carbon energy transition and high-quality development process as the nation makes strides to advance coal reduction and electricity replacing fuel programs, and to realize a cleaner and more efficient energy consumption. The 13th FYP period witnessed a significant drop in carbon emission intensity levels in China. In 2020, the national level of carbon dioxide emissions per GDP decreased by 18% compared with the 2015 level; and by 48.4% compared to 2005, equivalent to a cumulative reduction of approximately 5.7 billion tons of carbon dioxide emissions, exceeding China's commitment to the international community, basically reversing the rapid growth of carbon dioxide emissions. The same year also saw China's renewable energy generation capacity reaching 2210 TWh, which is estimated to a saving of about 680 Mtce and reductions of carbon dioxide (CO_2), sulfur dioxide (SO_2) and nitrogen oxide (NO_X) emissions by about 1790 million tons, 864,000 tons and 798,000 tons, respectively. Since 2010, China's energy consumption intensity has dropped by 28.7%, making China one of the countries with the fastest reduction in energy consumption intensity in the world.

Electrification on the energy consumption side continues to grow

The transition to low-carbon electrification on the energy consumption side continues to accelerate in China. In 2020, China's non-fossil energy accounts for 15.9% of TPEC, and the share of coal consumption declined to 56.8%. During the 13th FYP period, the share of non-fossil energy consumption continued to rise. Renewable energy accounted for about 13.9% of TPEC, an increase of more than 3 percentage points compared with the 2016 level; China's renewable energy power generation accounted for 29.5% of total electricity consumption, a five-fold increase compared with the 2005 level. From 2016 to 2020, China's total renewable energy power consumption expanded at an average annual growth of over 10%, or a near 1.5-fold increase in five years, including an over 2.3-fold increase in non-hydro renewable power consumption during the five-year period. China is also currently the world's largest electric vehicle market, with 4.92 million new energy vehicles nationwide in 2020, of which 4 million are electric vehicles (EVs). China has installed more than 2.22 million EV charging facilities. The scale of production and sales of new energy vehicles has ranked first in the world for six consecutive years.

Renewables experience leapfrog development

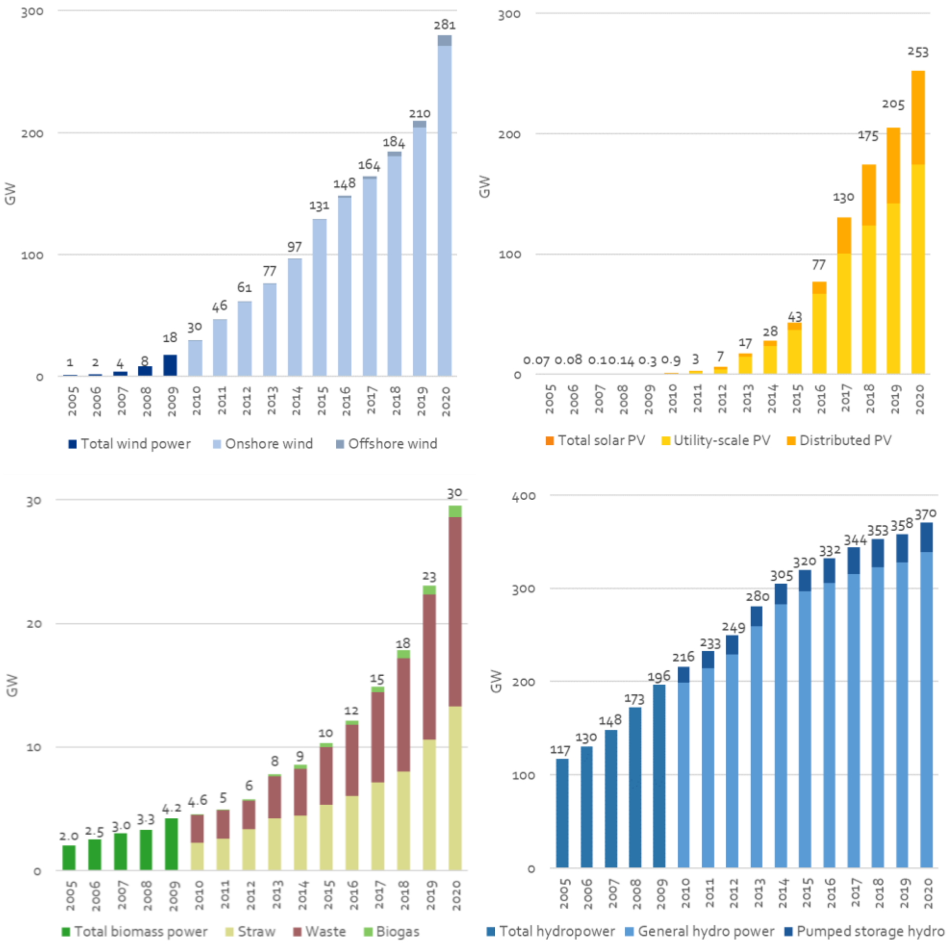
China continues to facilitate the scaled-up development of renewable energy. In 2020, China's installed renewable power generation capacity reached 934 GW, accounting for nearly one-third of the global total, ranking the first in the world, with a nearly seven-fold increase in scale compared with the 2005 level and an average annual growth rate of 14%.

In particular, non-hydro renewable power technologies, mainly refer to wind, solar and biomass, have together dominated the country's incremental power capacity. The cumulative capacity of installed wind power has ranked the first in the world for 11 consecutive years since 2010; new and cumulative capacity of installed PV power generation has ranked the first in the world for 5 consecutive years since 2015; biomass power has become the key solutions to solve rural agricultural and forestry residues and urban waste in China. As of the end of 2020, the cumulative installed capacity of wind power reached 281 GW, a 264-fold increase compared with the level of 2006 when the *Renewable Energy Law* was published; the cumulative installed capacity of solar PV was 253 GW, compared to the level of 2006 (80 MW); the cumulative installed capacity of biomass power reached 30 GW, a 15-fold increase compared with 2006.

The development of hydropower started very early and now has the largest share in China's renewable power capacity mix. So far, apart from the Tibet, the exploitation of hydropower resources nationwide has reached a relatively high-level. By 2020, the cumulative installed capacity of hydropower was 3700 GW, of which 3400 was general hydropower plants and 30 GW was pumped storage plants. The average annual growth rate of both during the 13th FYP period was slower than that of in the 12th FYP period, while the drop of general hydropower was sharper. With the increasing share of variable renewable power generation, as a key dispatchable power source to provide power system flexibility, pumped storage will play more important role in the future.

China's leapfrog development of renewable energy benefits from vigorous policy promotion and system building, including the promulgation and implementation of the *Renewable Energy Law*, the continuous formulation of medium- to long-term development plans and FYPs for renewable energy, the continuous improvement of policies for renewable energy grid connection and consumption, the introduction of renewable power feed-in tariff policies, the implementation of a renewable energy surcharge allocation and compensation system, the establishment of renewable energy development funds, and the issuing of renewable power feed-in tariff subsidies, amongst others.

Figure 2-9: Cumulative installed capacity of wind, solar, biomass and hydro power in China from 2005 to 2020



Source: National Energy Administration (NEA), Energy Research Institute of the National Development and Reform Commission (ERI of NDRC), accessed in October 2021

China remains to be one of the largest renewable energy investment markets

China is among world leaders in energy transition investment. According to Bloomberg, in 2020, of USD 501.3 billion total energy transition investment worldwide (including USD 303.5 billion in renewable energy), China contributed to USD 135 billion, or a quarter of the world's total, ranking first for a single country; compared with China, the European investment was USD 166.2 billion.[22] In the first half of 2021, the global renewable energy investment totalled USD 174.3 billion. China once again ranked the first of the world's largest renewable energy market, with a total of USD 45.5 billion investment made in this period.[23] SolarPower Europe predicts that global new PV installations are expected to reach 163 GW in 2021, with China, the United States and India remaining the three largest markets.[24] China's continued investment in new energy technologies and equipment, such as PV module, wind turbine, electric vehicle and power battery, has contributed to global declines in the costs of new energy technologies.

Large-scale of power generation units adopt energy saving and low-emission retrofit

China has made considerable efforts in exploring the reduction and cleaner use of coal, energy conservation and emission reduction. In recent years, China has vigorously promoted the implementation of ultra-low emission and energy-saving retrofit projects in domestic power generation enterprises, and has built the world's largest coal power supply system with low particulates, SO_2, and NO_x emissions.[25] Meanwhile, China has stepped up efforts to eliminate outdated coal power capacity. As of the end of 2019, a total of more than 100 GW of outdated coal power capacity had been eliminated[26]; by October 2021, the figure reached 120 GW. The share of coal-fired power generation capacity dropped from 65.7% in 2012 to 52% in 2019.[27] Power generation efficiency and pollutant emission control levels of coal-fired units also reached the world's advanced level.

Effectively combines solar PV development with poverty alleviation

In addition, China has conducted useful explorations on low-carbon energy poverty alleviation models, thus making contributions to the global energy accessibility process and the United Nations 2030 Sustainable Development Goals. After attaining the goal of 100% access to electricity nationwide in 2015[28], China is now creatively exploring the PV poverty alleviation model nationwide by combining energy access with poverty alleviation efforts. According to data of the National Energy Administration (NEA), as of the end of 2019, China had built a total of 26.4 GW of PV power plants to alleviate poverty, benefiting 4.15 million households and generating a revenue of about RMB 18 billion per annum from power generation. As of the end of 2020, village-level PV power plants covered a total of 92,300 villages in 26 provinces (and autonomous regions), of which 59,800 were archived poverty-stricken villages, meaning nearly half of the country's archived poverty-stricken villages had village-level PV poverty alleviation power plants in place, which on average add an annual stable income of more than RMB 200,000 per village. It has become a model project for “poverty alleviation by developing industries” and one of the top 10 targeted poverty alleviation projects in China.[29]

Despite its leapfrog development in the new energy sector and constant acceleration in low-carbon transition, China remains to be the world's largest developing country and the world's largest consumer of energy, coal and fossil energy. China needs to make greater practical and exploratory efforts to realize its carbon peaking and carbon neutrality targets while ensuring economic transformation, and safeguarding people's livelihood and social prosperity.

Part 2: The Chinese pathway to Carbon Neutrality

3 The Chinese energy system transformation to 2060

3.1 The CETO 2022 scenarios

In CETO22, two main scenarios are developed to analyse the transformation of the Chinese energy system from the present high-carbon system to the carbon-neutral system in 2060. The scenarios detail pathways for comprehensive energy system reform. From the present situation, the overall energy production and consumption mix stands on the precipice of a revolution in both two main scenarios.

Baseline Scenario and Carbon Neutrality Scenarios

The scenarios in CETO comprise two development pathways for the Chinese energy system. The Baseline scenario (BLS) shows a development, where China contributes to the global 2-degree goal and achieves carbon neutrality around 2070. A Carbon Neutral Scenario (CNS) illustrates the pathways for achieving the dual goals of peaking carbon dioxide emission before 2030 and achieving carbon neutrality before 2060.

The Baseline Scenario (BLS)

The scenario assumes full and firm implementation of the expressed energy sector and related policies. Central priorities are the efforts to build a clean, low-carbon, safe and efficient energy supply and to develop a harmonious and beautiful China by 2050. The scenario takes account of the previously announced policy to peak emissions by 2030, and to have a low-carbon energy sector by 2060. In this scenario, carbon neutrality is expected to be reached in 2070.

Carbon Neutrality Scenario (CNS)

The Carbon Neutrality scenario shows a roadmap for China to achieve the ambitious vision for an ecological civilisation and the pathway China could take towards carbon neutrality. The main driver is a hard target for energy-related CO_2 emissions with the overall direction of moving towards net-zero carbon emissions in 2060.

Two different scenario methodologies

The scenario methodology is in general a bottom-up approach using energy system models for the different end-use sectors and a detailed power system optimisation model. However, two different approaches for the detailed analyses are used to consider the special expectations and presumptions for the Chinese development pathways compared with a more stringent model optimisation approach, where the model assumptions are allowed to have a stronger influence on the results.

Hence, the first pair of scenarios, the BLS1 and the CNS1, is based on the Chinese National Statistics and on a heuristic approach based on previous modelling studies, including the 2050 High RE Share Scenario analysis, the Reinventing Fire China study, and the various China Renewables Outlook scenario analyses. Also, the scenarios consider the transformation experiences from pilot provinces and the experienced barriers for a low-carbon energy transformation in China. The second pair of scenarios, the BLS2 and the

CNS2, supplement the National Statistics with additional information about the use of energy for heating based on additional sources and use a more stringent least cost optimisation approach for the power sector pathway. Both methodologies use the same overall framework assumptions explained below and the same modelling background.

3.2 Main Scenario Assumptions

Top level targets for the energy transition

The top-level targets for China's energy transition are *carbon emissions reductions*, *sustainable economic growth* and guaranteeing *long-term energy security*.

Carbon peak and carbon neutrality

The overall target is securing the low climate impact from the energy sector, to implement China's commitment to the Paris Agreement, follow a low-carbon development pathway, and contribute to the global target of limiting global mean temperature increase below 2 °C.

For both scenarios, the carbon emission from the energy system should peak before the end of 2030. For the Baseline Scenario, the long-term target is to have a low-carbon energy system by 2050 and to reach carbon neutrality before 2070. For the Carbon Neutrality Scenario, the target is to reach carbon neutrality before 2060.

Economic growth

Economic growth is bottom line precondition of China's socioeconomic objectives for long-term development. It is required that GDP grows 4.29 times from 2019 level in real terms by 2060. The growth shall be sustainable and supported by the transition of the Chinese energy system to build in the properties of *clean, low-carbon, safe and efficient* – and essential component in the efforts to build China's Ecological Civilisation.

CO_2 emissions and the pathways for reduction

The calculations of the CO_2 emissions in this CETO report covers all CO_2 emissions from energy-related activities in China, ranging from energy production, energy processing and conversion, to energy end use.

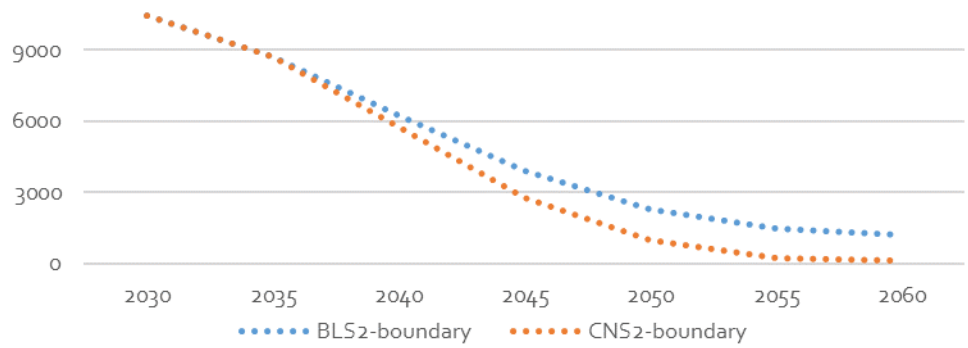
According to the GHG inventory figures reported in the National Communications on Climate Change of the People's Republic of China and the Biennial Updated Reports on Climate Change of the People's Republic of China, CO_2 emissions from energy-related activities, which is covered by this CETO report, shared a majority of 76.6%-79.8% of China's total GHG emissions (including LULUCF) (see Table 3-1).

Table 3-1: Energy-related CO2 emissions and shares in annual greenhouse gas (GHG) emissions for China

Category	1994	2005	2010	2014
CO_2 emissions from energy-related activities (Gg CO_2 equivalent)	2,795,489	5,665,000	7,623,859	8,924,929
Total GHG emissions including LULUCF/LUCF (Gg CO_2 equivalent)	3,650,138	7,249,000	9,550,151	11,185,410
Shares in national total (%)	76.6	78.1	79.8	79.8

The main difference driving the two scenarios is the alternative pathways for carbon emissions reductions. Even before the carbon neutrality pledge, China has been gearing up for a reversal of past trends in energy emissions, and successive scenario studies, including the China Renewable Energy Outlook publications of past years have shown that this change is in China's interest regardless. Achieving carbon neutrality, however, is a significant increase in the level of ambition, and the scenarios are designed to highlight the additional measures that need to be considered to achieve that level of deep decarbonisation in the Chinese economy. Figure 3-1 shows the assumed trajectory for the CO2 emission development in the Baseline and the Carbon Neutrality scenarios. The CNS requires deeper decarbonisation than the BLS after 2035.

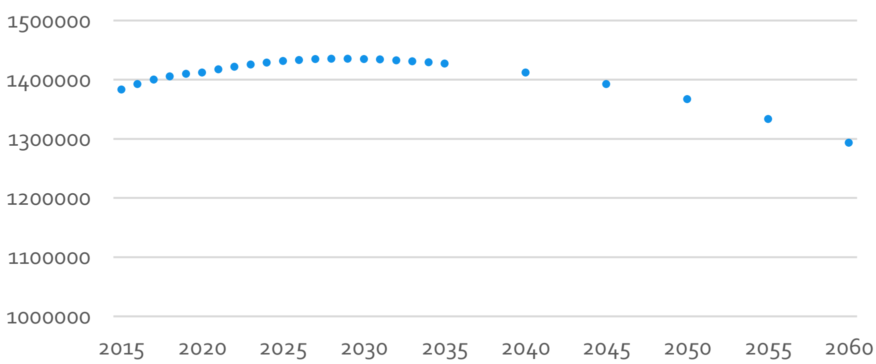
Figure 3-1: Assumed boundaries of energy sector CO2 emissions for the two scenarios (Mton/year)



Demographic assumptions

The population assumptions of this CETO consider the population forecasts made by leading international and domestic organisations, including the World Bank, the Chinese Academy of Macro-Economic Research, the Chinese Academy of Social Sciences and others. Comparison of the variety of population forecasts shows that the turning point of China's population growth is likely to appear in the next decade, combining with fluctuating and declining birth rates and an aging population structure. The projections applied as assumptions in this CETO is 1.43 billion in 2030, 1.37 billion in 2050 and 1.29 billion in 2060 (see Figure 3-2).

Figure 3-2: China's total population projection applied in CETO 2022 (unit: thousand people)



While China's population is projected to only grow slightly in the short term and contract from present until 2060, the rate of urbanisation will grow significantly which influences the populations consumption patterns and the energy services needed to support this. From the 2018 level of 55% according to the National Bureau of Statistics, urbanisation should increase to 69% by 2030. According to CETO assumptions, 78% of citizens would be living in urban areas by 2050.[30]

Cost pathways for key technologies in the power sector

The power sectors energy transformation is modelled in ERIs EDO model. At the core, this is a least-cost capacity expansion, unit commitment and dispatch optimisation model. It provides the cost-efficient means to satisfy boundary conditions including the electricity demand, district heating demand, subject to further policy constraints including, in the present analyses, the yearly cap on CO_2 emissions attributed in the power and district heating sectors as an apportionment of the overall cap in energy related CO_2 emissions. Key inputs informing this cost-optimisation based trajectory include the assumptions regarding the evolution of technology and fuel costs.

Table 3-2 indicates costs of key technologies for which there is an expectation of considerable development (cost decline) from today's levels. In contrast, we estimate limited development in the investment costs for conventional technologies such as thermal plants.

Table 3-2: Overview of the assumed investment costs of the key technologies (in million RMB/MW, RMB/tCO_2 for CCS)

Technology	2020	2035	2050	2060
Onshore wind	7.20	5.50	5.10	5.10
Offshore wind	14	8.40	7.70	7.70
Utility Solar PV	3.20	2.10	1.60	1.60
Distributed Solar PV	3.04	1.97	1.44	1.44
Lithium-Ion battery	6.40	4.80	2.00	2.00
Carbon capture and sequestration	415	355	178	137.5

The competitiveness of fossil-fired thermal plants, will, however, be affected by the evolution in fuel prices (assumptions presented in Table 3-3 and Table 3-4) as well as a shrinking allocation of CO_2 emissions as the scenarios move towards decarbonisation and carbon neutrality.

Table 3-3: Average fuel prices (RMB2020/GJ)

	2020	2025	2035	2060
Natural gas	42.9	28.4	26.0	22.9
Coal	21.7	16.4	13.9	12.3
Straw	26.17	29.0	33.6	42.5
Wood	34	36	40	50
Biogas	57	62	69	84

Table 3-4: Max and min fuel prices (RMB2020/GJ) for selected fuels

	2020		2025		2035		2060	
	max.	min.	max.	min.	max.	min.	max.	min.
Natural gas	52.3	26.4	34.6	17.5	31.8	16.0	28.0	14.1
Coal	29.2	10.6	21.0	9.6	16.5	10.2	12.8	11.5
Straw	34	22.4	37.7	24.8	43.7	28.7	55.2	36.3

The fuel prices considered for the analysis are shown in the table above. Here the coal and natural gas values are based on two references. A general trend in coal and natural gas prices in China is estimated based on the fuel price data from IEA's Net Zero by 2050 report[31]. For the price variation across provinces, the historical price data from NDRC and Inner Mongolia Coal Exchange Center is considered. Based on these inputs a forecast for the price development is calculated.

Key strategies for China's energy transformation

Phase-down coal and oil

As an overall hypothesis for a sustainable low-carbon or carbon neutrality pathway, the short- and medium-term strategy on the supply side would include coal consumption reduction, oil consumption stability, gas consumption increase and boosting RE deployment. In the medium and long term, the strategy will transfer into a deep coal phase-down, oil reduction, gas stability and massive RE deployment, and finally, the strategy will focus on a deep oil phase-down, gas reduction and continuous RE deployment. Throughout the period, the strategy will include energy efficiency measures in all end-use sectors and increased electrification of especially in the industry and transport sector.

Electrification of industry, transport and hydrogen production

Electrification is the critical measure to decarbonise all the end-use sectors. It is assumed that the total share of electricity and power-based alternative fuels grows substantially towards 2060. Alongside the growth in the direct use of electricity in end-use sectors, there is also a huge increase in the use of electricity for hydrogen production.

The reduction of coal in the industry will be through the transition of steelmaking and coal chemical industries. Steel production needs to be reduced to achieve the carbon neutrality goal, by 2035, the total steel production is assumed to decline by 20%, and 2060 by 40%. In CNS2, electric arc furnace (EAF) and direct reduced iron (DRI) is expecting to eventually replace the current energy-intensive and coke-based production. Low carbon hydrogen-based green chemical is assumed to develop on a large scale from 2035.

In transport, electrification is through the quick penetration of EVs in passenger vehicles. By 2035, the market share of new electric vehicles (NEV) of annual passenger vehicles sales is assumed to reach 100%. Heavy trucking, aviation and shipping need to adopt other strategies due to the difficulty of electrifying. FCV will be the mainstream vehicle in cross trucks, whose market share takes up to 70% in 2050. Aviation relies largely on biofuels and fuels from power generation (PtX), and ammonia is vital for shipping.

More energy-efficient buildings

In buildings, energy efficiency improvement has a high priority. By adopting more strict building codes, the energy intensity will decline significantly. Even with a large increase in the building stock, the total energy demand will stay within a reasonable range. We foresee an enlarged district heating system due to the flexibility it brings through sector coupling. More electricity is expecting to be used to provide district heating via large scale heat pumps and large electric boilers.

3.3 Policy instruments for the transformation by sector

Both scenarios are guided by official policy targets as described in policy documents. These include China's new Nationally Determined Contributions (NDC) and *the 14th Five-Year Plan for Economic and Social Development.* As mentioned earlier, the Baseline Scenario (BLS) does not take into account the carbon neutrality targets for 2060 or the new NDC targets.

Power market reform and CO2 ETS are key boundary conditions

The key power sector policy instruments guiding the development of the scenarios are:

- Power market reform – Since March of 2015, China's has been undergoing a critical process of market reform, whose implementation and success is considered a precondition in the scenarios. [32] Most critically, dispatch becomes increasingly market-based within provinces and power flow schedules between provincial and regional grides are increasingly adjusted closer to operation, using as spot markets. The procurement and provision of ancillary services to provide short-term flexibility and contingency response is increasing provided on market terms and barriers for cost-efficient sharing of reserves between regional grids are lowered.
- Carbon emissions reductions are imposed on the energy sector and specifically as hard constraints on the power sector.

The importance of, and recommendations concerning, the successful implementation of the power market reform process is further elaborated in Chapter 5. The status and perspectives for China's ETS to deliver the carbon emissions reductions outlines in the scenarios is detailed in Chapter 6. Since the power and district heating sectors are represented in a distinct model from end-use sectors and other transformation sectors, the overall CO2 boundary constraint is apportioned between the models representing different sectors.

In the modelling of the power sector, a number of constraints are implemented to reflect continued support for emerging technologies which appear unable to complete in the short run, on a pure cost basis. These include:

- Concentrated Solar Power (CSP)
- Geothermal power generation
- Geothermal heat generation
- Offshore wind (supported mainly at provincial level)
- Ocean energy
- Biomass based generation including waste incineration in waste-to-energy plants

Concrete capacity development plans of certain provinces regarding pumped-hydro storage capacity as assumed to be realised until 2030. Finally, the deployment of nuclear power and hydro power generation capacity is not cost optimised but follow a common path in both scenarios based on the resource and siting constraints.

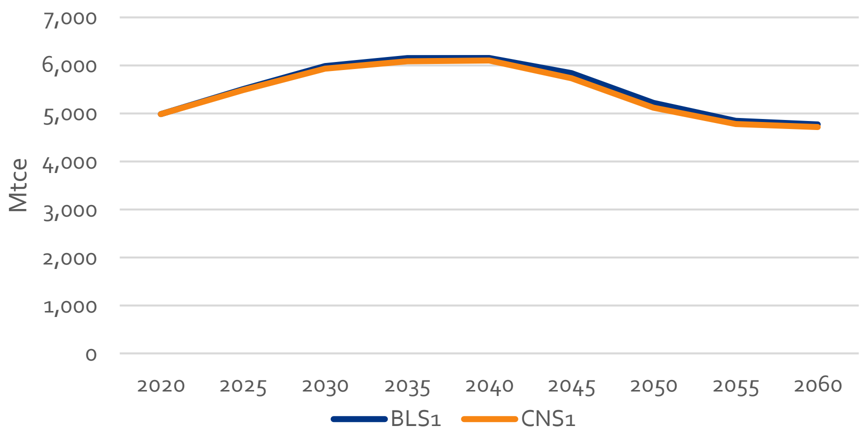
3.4 Scenario results 1

In this session the scenario study based on the heuristic methodology is presented. The base year figures are from the national statistics and the results are presented using the coal substitution method for calculating the primary energy demand. In this calculation method, the power production from renewable energy is calculated as substituted coal from an equivalent power production from coal fired power plants.

Primary energy consumption trend

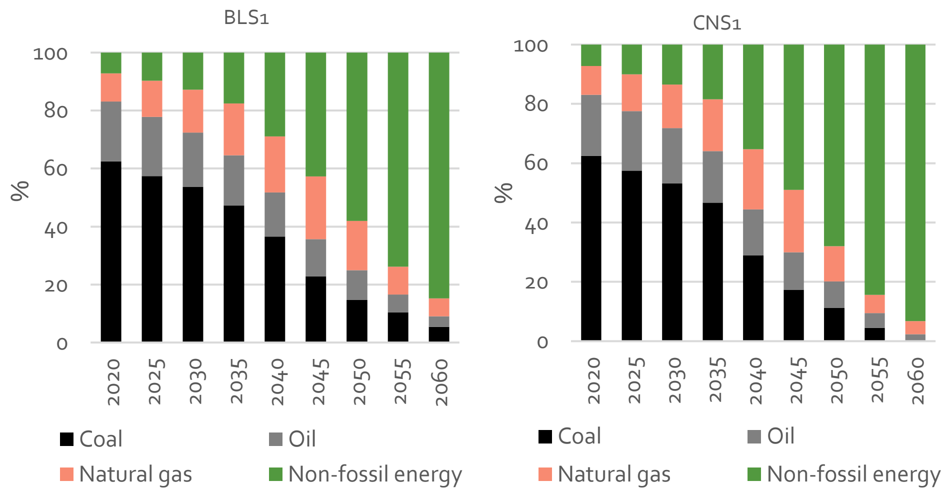
As a result of the different drivers for the energy transformation, the total primary energy consumption has an almost identical development trend in the two scenarios.

Figure 3-3: Total Primary Energy Consumption (Mtce) in the two scenarios 2020 – 2060 (coal equivalent calculation)



In both scenarios, non-fossil fuels and natural gas gradually substitute coal from 2020. In 2035, non-fossil fuels cover 32% of the total primary energy consumption in BLS1 and 34% in CNS1. In 2050, the share is 73% in BLS1 and 82% in CNS. In 2060, the share is 91% in BLS1 and 97% in CNS1 (coal equivalent calculation).

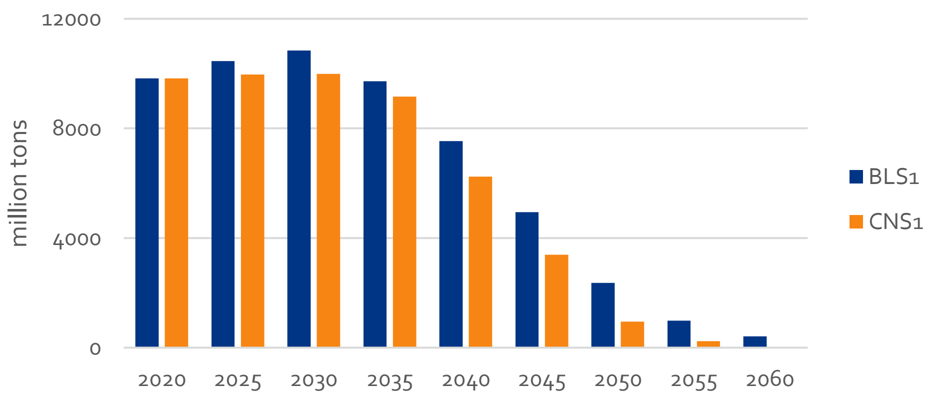
Figure 3-4: Fuel shares in the Total Primary Energy Consumption (%) (coal equivalent calculation)



CO_2 emission peak before 2030

The CETO scenarios show that it is possible to have a CO_2 peak before 2030 for the Chinese energy sector, as shown in Figure 3-5. The CNS1 has a lower CO_2 emission throughout the period to 2060 compared with the BLS. The CNS1 reaches carbon neutrality before 2060, while the BLS1 still has CO_2 emissions. However, both scenarios have a steady decrease in CO_2 emissions after 2030.

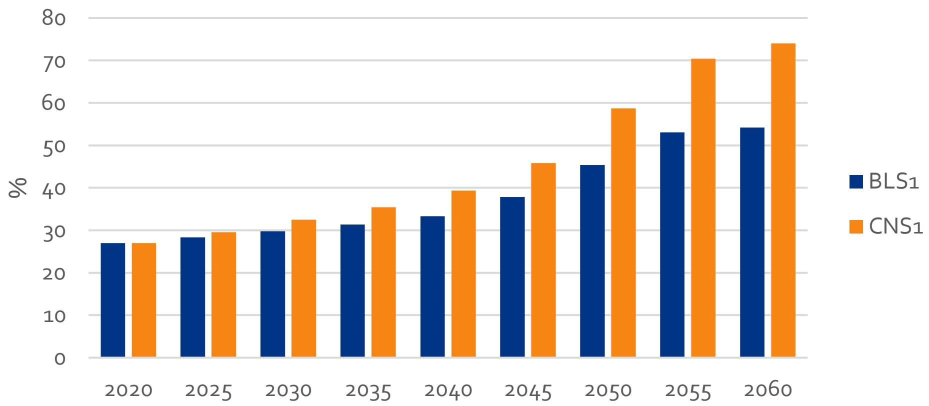
Figure 3-5: Energy sector CO2 emissions in the CETO scenarios from 2020-2060 (million tons)



Electrification strategy decreases coal and oil in the end-use sectors

An essential part of the energy transformation is to substitute fossil fuels in the end-use sectors with electricity from a green power system. Furthermore, the introduction of green hydrogen produced by wind and solar power is an indirect way to electrify the end-use sectors. With the deepening of industrial electrification (especially the iron industry) and the promotion of electric vehicles, electricity consumption will increase substantially. In 2060, the general electrification rate in the end-use sectors reaches 54% in the BLS1 and 74% in the CNS1.

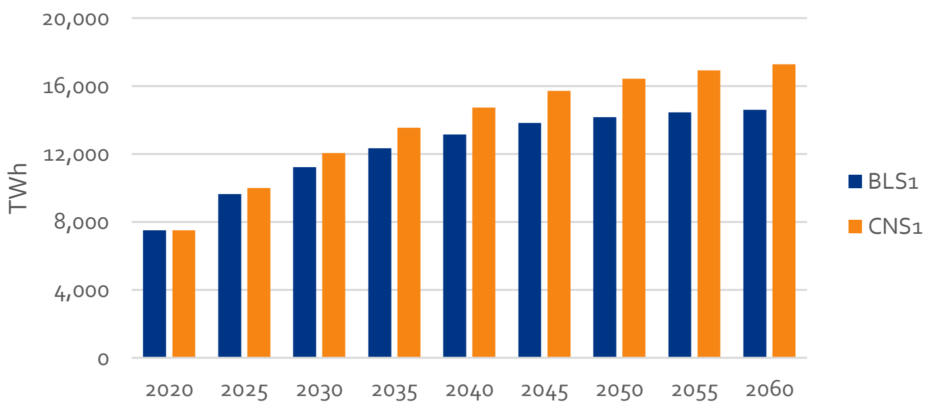
Figure 3-6: Electrification rate (%) development 2020 – 2060 in the BLS1 and CNS1



Electricity consumption keeps increasing trends in both scenarios

Under both scenarios, China's total electricity consumption shows an upward trend, while the electricity consumption is generally higher in the CNS1 than in the BLS1 due to the more ambitious electrification of the end-use sectors. In the CNS1, the total electricity consumption reaches 12,000 TWh in 2030 and further to 17,300 TWh in 2060, suggesting a twofold increase in total power consumption from 2020 to 2060.

Figure 3-7: Electricity consumption in the two scenarios (TWh)

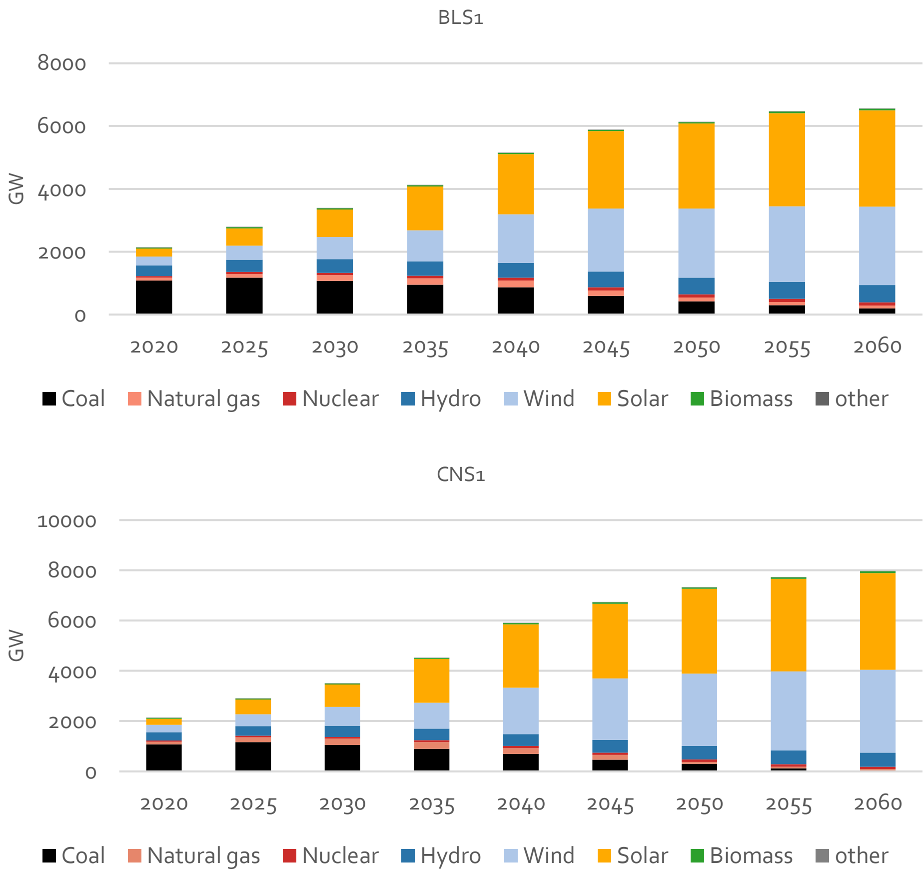


Solar and wind power make the power sector green and clean

The CNS1 has 760 GW of wind power and 890 GW of solar power to a combined 1,650 GW by 2030, and the total installed capacity of wind power and solar PV is thereby higher than the target of 1,200 GW. This is mainly due to the expected economic competitiveness of wind and solar compared with other technologies, combined with the target to have a CO_2 peak before 2030. The BLS1 has 707 GW of wind and 880 GW of solar installed in 2030.

By 2060, the cumulative installed capacity of wind and solar further increases to 7,145 GW in CNS1, of which 3,300 GW is wind power and 3,845 GW is solar power. The BLS1 has 2,500 GW of wind and 3,070 GW of solar installed in 2060.

Figure 3-8: Installed power capacity in the two scenarios (GW)



Renewable power will dominate power generation mix in the long-term future

In both scenarios, the total electricity generation grows in the period towards 2060, doubling from around 7,500 TWh in 2020 to almost 14,600 TWh in 2060 in the BLS1, and has an increase to 17,300 TWh in the CNS1. Coal-based power production is gradually phased-down and replaced by electricity from renewable energy, mainly solar PV and wind turbines. The share of renewables in power production increases from nearly 30% in 2020 to 92.5% in 2060 in the BLS1 scenario and 95.5% in the CNS1.

Figure 3-9: Power generation in the two scenarios (TWh)

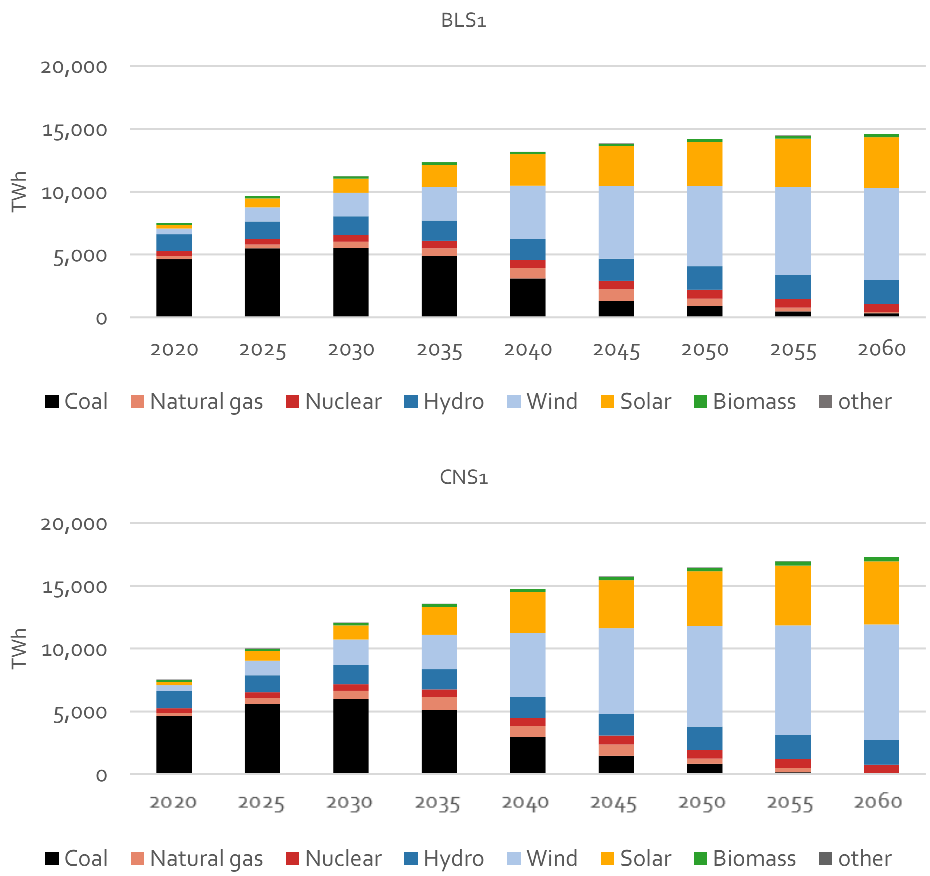


Figure 3-10: 2020 China Energy Flow Chart (Mtce)

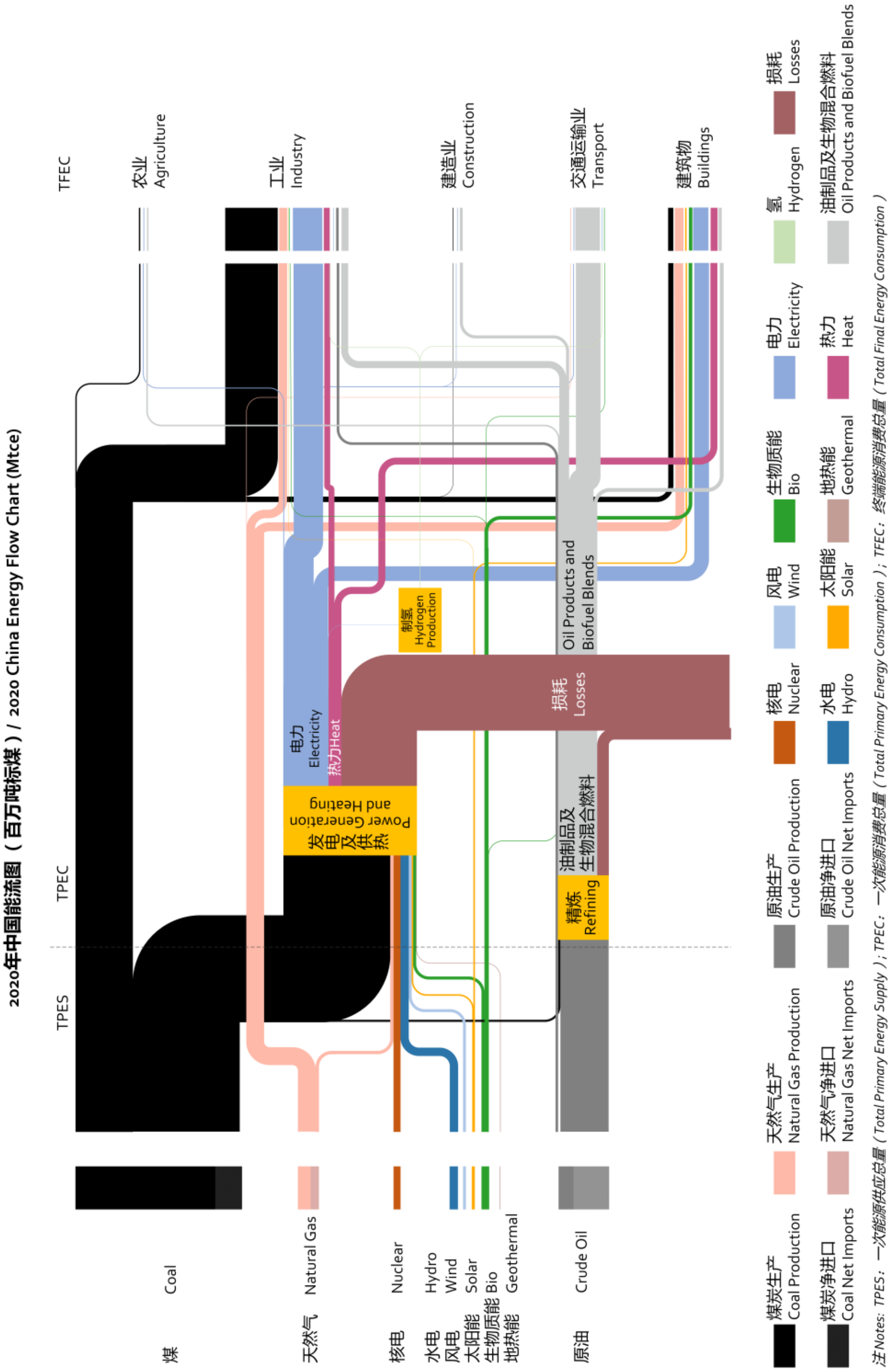
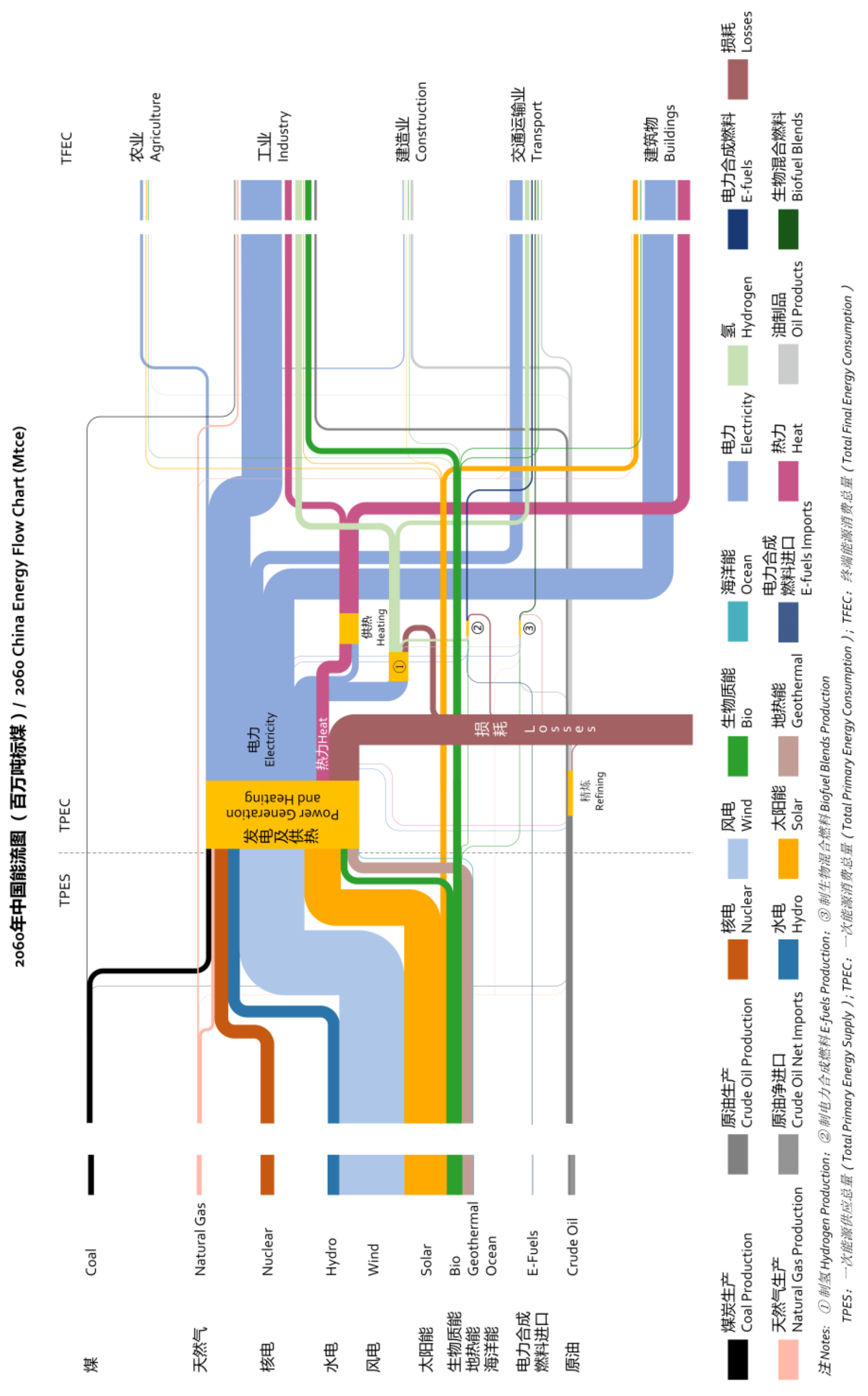


Figure 3-11: 2060 China Energy Flow Chart (Mtce) in CNS1



3.5 Scenario results 2

The overall development of the energy system in the two pathways in China Energy Transition Outlook 2021, is an aggregation of strategic roadmaps and developments in key subsectors including power, heating, transport, and industry etc. This leads towards a total transformation of the energy system by 2060.

The main contributions from new energy sources are from wind and solar power. Nuclear capacity is by assumption the same in the two scenarios. Specific details and challenges regarding these technologies deployments are covered further in Chapter 5 which focuses on the power sector.

The key indicators of the two pathways are presented in Table 3-5 and Table 3-6, aggregating the combined energy system effects of the detailed roadmaps.

Table 3-5: Key figures in the energy sector development in the BLS2

		2020	2025	2030	2050	2060
Coal substitution method						
Total Primary Energy Supply (TPES)	*Mtce*	5,245	5,582	5,762	5,011	5,001
Energy intensity		52	43	36	16	12
Non-fossil fuel share of TPES	*%*	15%	22%	30%	75%	83%
RE share of TPES	*%*	13%	19%	26%	70%	78%
Energy basis						
Total Primary Energy Supply (TPES)	*Mtce*	5,017	5,174	5,213	3,482	3,327
Total Final Energy Consumption (TFEC)	*Mtce*	3,608	3,754	3,763	3,096	2,849
Energy intensity	tce/mRMB	50	40	32	11	8
Non-fossil fuel share of TPES	*%*	11%	15%	22%	63%	74%
RE share of TPES	*%*	8%	11%	18%	56%	67%
Coal share of TPES	*%*	60%	54%	47%	8%	6%
Coal share of TFEC	*%*	32%	24%	17%	6%	4%
Gas share of TPES	*%*	8%	10%	13%	16%	10%
Oil share of TPES	*%*	22%	21%	19%	13%	10%
Electrification (direct) of TFEC	*%*	26%	32%	38%	61%	71%

Table 3-6: Key figures in the energy sector development in the CNS2

		2020	2025	2030	2050	2060
Coal substitution method						
Total Primary Energy Supply (TPES)	*Mtce*	5,247	5,594	5,798	5,254	5,174
Energy intensity		52	43	36	16	12
Non-fossil fuel share of TPES	*%*	15%	22%	31%	87%	94%
RE share of TPES	*%*	13%	19%	27%	82%	90%
Energy basis						
Total Primary Energy Supply (TPES)	*Mtce*	4,978	5,146	5,177	3,408	3,169
Total Final Energy Consumption (TFEC)	*Mtce*	3,608	3,731	3,709	2,875	2,656
Energy intensity	tce/mRMB	49	40	32	11	7
Non-fossil fuel share of TPES	*%*	11%	15%	23%	80%	91%
RE share of TPES	*%*	8%	12%	19%	72%	83%
Coal share of TPES	*%*	60%	55%	48%	3%	2%
Coal share of TFEC	*%*	32%	24%	17%	3%	0%
Gas share of TPES	*%*	8%	10%	12%	11%	3%
Oil share of TPES	*%*	21%	20%	17%	6%	4%
Electrification (direct) of TFEC	*%*	26%	33%	41%	80%	92%

Primary energy demand shifts from fossil to non-fossil towards 2060

The overall energy mix by 2060 is presented in Figure 3-12 for both scenarios. The primary energy demand in both scenarios shifts from mainly fossil to mainly non-fossil in both scenarios by 2060. In the BLS2, the share of non-fossil accounts for 74% by 2060 and as much as 91% in the CNS2, making renewables the core of the energy supply in the system for both scenarios. Wind constitutes the largest share of energy sources with 30% and 42% respectively to the two scenarios.

The transition in the scenarios on the supply side is driven by a combination of ambitious targets, firm policy implementation and continuous cost reductions in alternatives – particularly renewable energy sources. Costs alone can drive expansion of competitive renewable energy projects, but policy support is needed to support the pace of transition in the scenarios. Strategic emphasis on the development of the flexible grid operations, power market design and other system flexibility measures drives more efficient integration of renewables in the system.

Figure 3-12: Total primary energy demand 2020

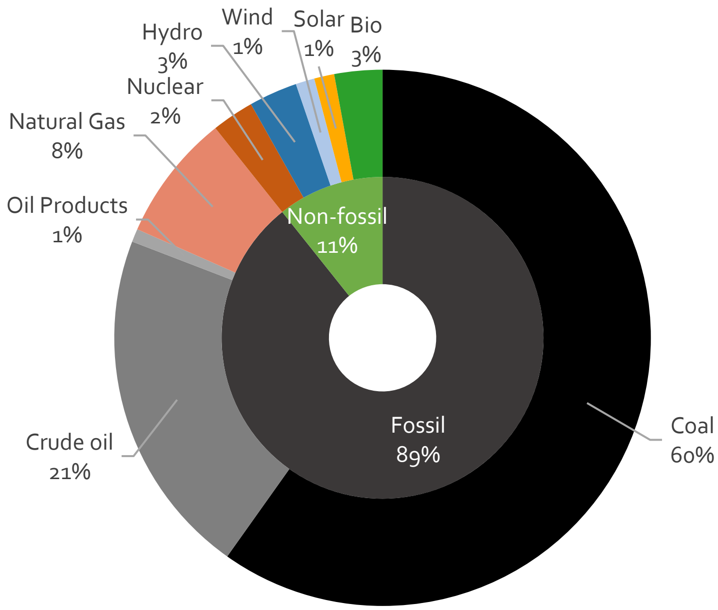


Figure 3-13: Primary energy demand in BLS2 in 2060

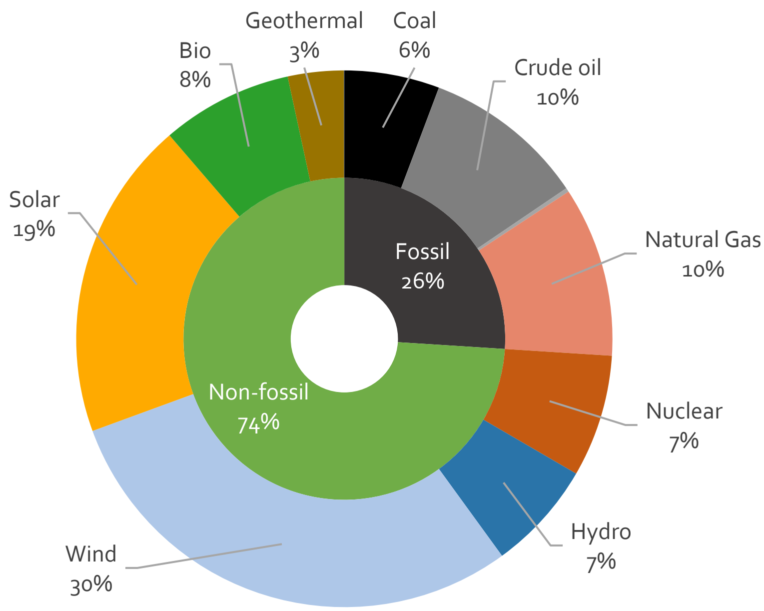
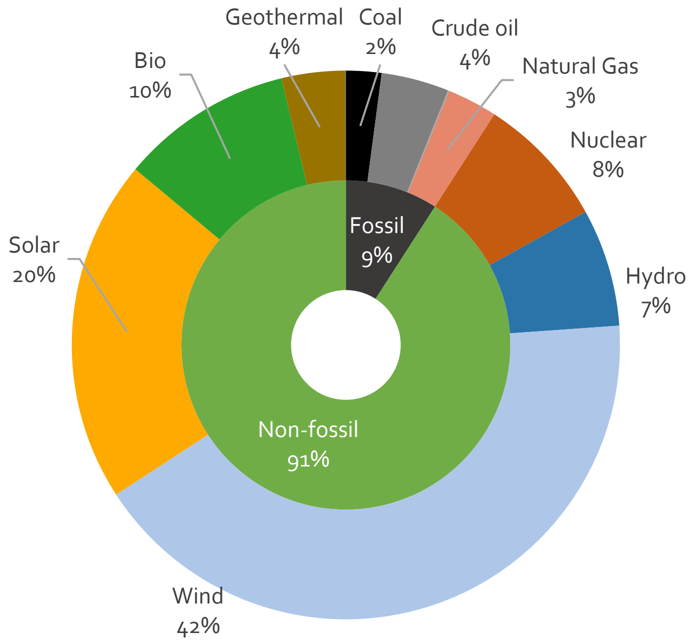


Figure 3-14: Primary Energy Demand in CNS2 in 2060



Final energy consumption shifts towards electrification, hydrogen, and direct consumption of renewables

In both the BLS2 and CNS2, the final energy consumption peaks before 2030. In the BLS2, the peak reaches 3772 Mtce (+5% of the final energy consumption for 2020) and it is reduced to 2849 Mtce by 2060 (-21% of the final energy consumption for 2020). In the CNS2, the peak reaches 3731 Mtce (+3% of the final energy consumption for 2020) and is reduced to 2656 Mtce by 2060 (-26% of the final energy consumption for 2020).

The final energy mix will shift away from fossil fuel and towards electricity, hydrogen, and renewables, resulting in lower CO2 emissions. The shares of coal in final energy consumption decreases in the BLS2 from 32% in 2020 to 13% in 2035 and 4% in 2060. In the CNS2, shares of coal in final energy consumption decrease to 13% and near-zero in 2035 and 2060, respectively.

Electricity as a share of final consumption increases from 24% in 2020 to 40% in 2035 and 52% in 2060 in the BLS2. In the CNS2, the shares of electricity increase to 43% and 61% in 2035 and 2060, respectively.

Figure 3-15: Development of final energy consumption (Mtce) by energy type from 2020-2060 in the BLS2

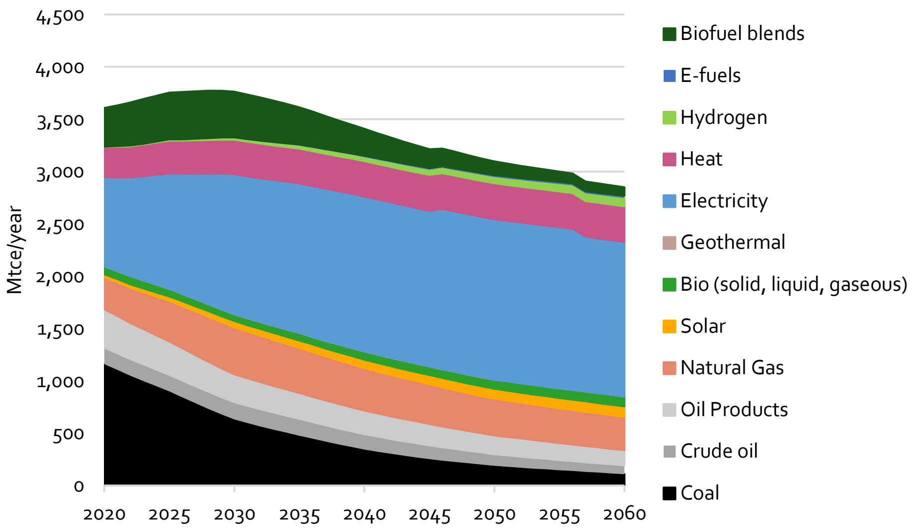
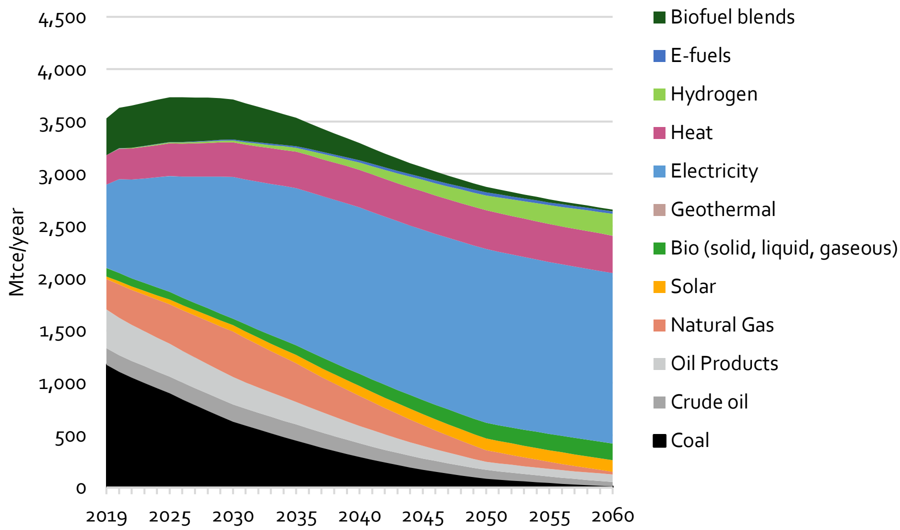


Figure 3-16: Development of final energy consumption (Mtce) by energy type from 2020-2060 in the CNS2



Biofuel blends in the transport sector increase in absolute terms but retain their proportional role in the final energy mix.

Hydrogen produced with electricity reaches 0.7% in 2035 and 2.7% in 2060 in the BLS2; in the CNS2, it reaches 1.1% in 2035 and 7.9% in 2060 in final energy consumption.

Energy efficiency and electrification enable clean transition with RE supply

The increase in energy efficiency and electrification are key steps in the clean energy transition, as the renewable energy shares expand, and the fossil energy shares decrease. To integrate the large quantities of low-cost wind and solar power in the system, electrification rates are increased, particularly in transport, buildings, and industry.

Figure 3-17: Final energy demand by carrier

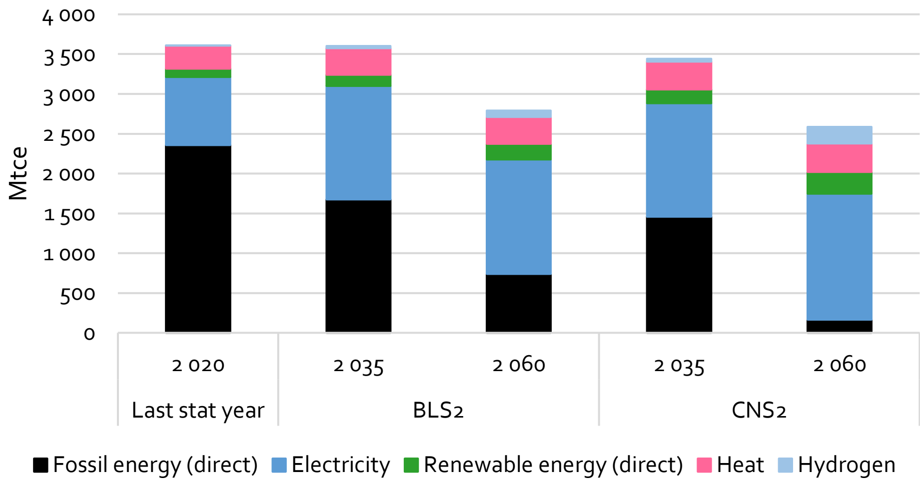
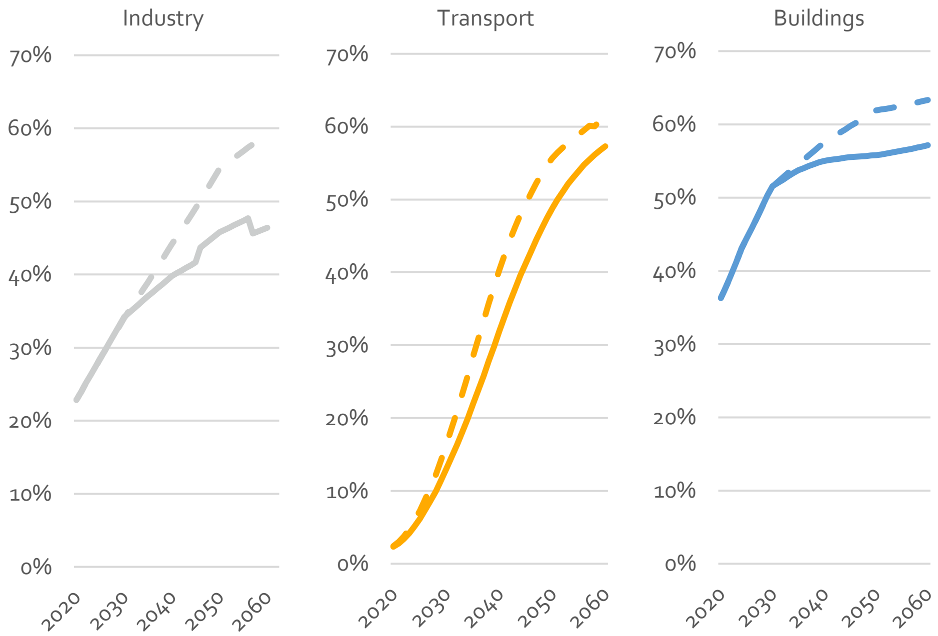


Figure 3-18: Electrification rate development in industry, transport, and building sectors. BLS2 straight line, CNS2 dotted line



In the transport sector, fossil based internal combustion engines are currently dominant in both heavy and light modes of transport. Towards 2060, penetration of new energy vehicles including EVs are key to decarbonising the sector. In the BLS2 an electrification rate of the transport sector gradually grows from 2% in 2020 to 57% and 61% by 2060, respectively to the BLS2 and the CNS2.

The electrification rate in the industry sector increases from 23% in 2020 to 46% by 2060 in the BLS2. In the CNS2, an electrification rate of 59% is achieved, just below the electrification rate of 63% in the buildings sector. Primary energy demand declines and shifts towards non-fossil fuels, particularly renewable sources.

In both scenarios, towards 2060, the main reductions of primary energy demand are found in coal and oil consumption. In the BLS2, the consumption of coal declines by 2811 Mtce from 2020 to 2060 in the BLS2, and by 2935 Mtce in CNS2.

Figure 3-19: The development of primary energy demand (Mtce) by energy type from 2020-2060 in the BLS2

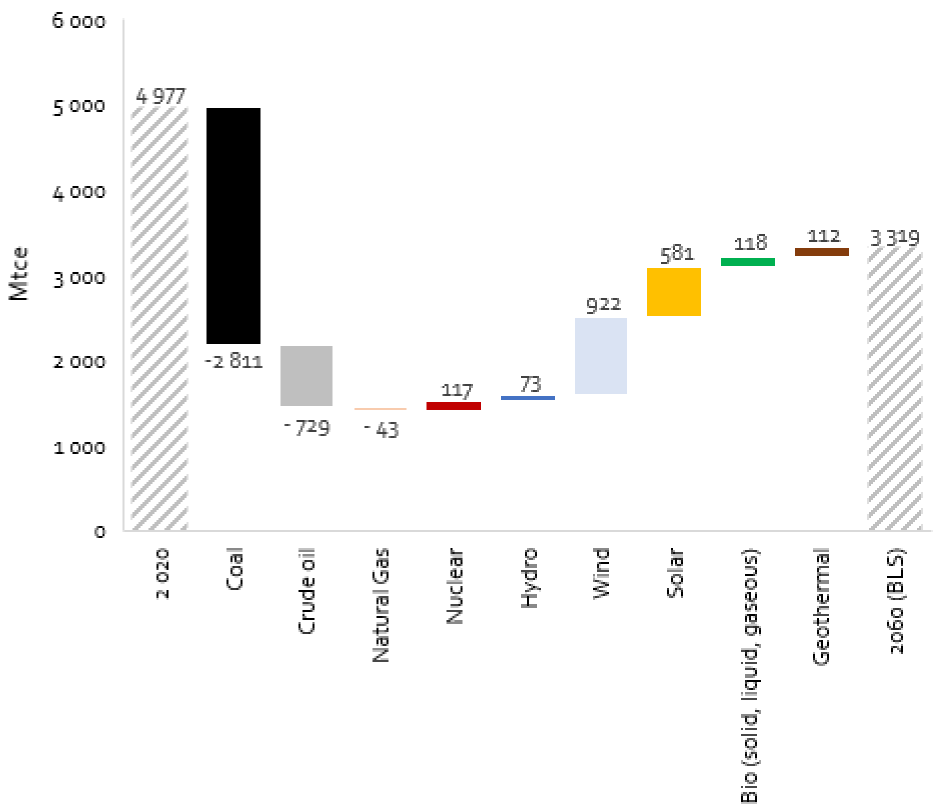
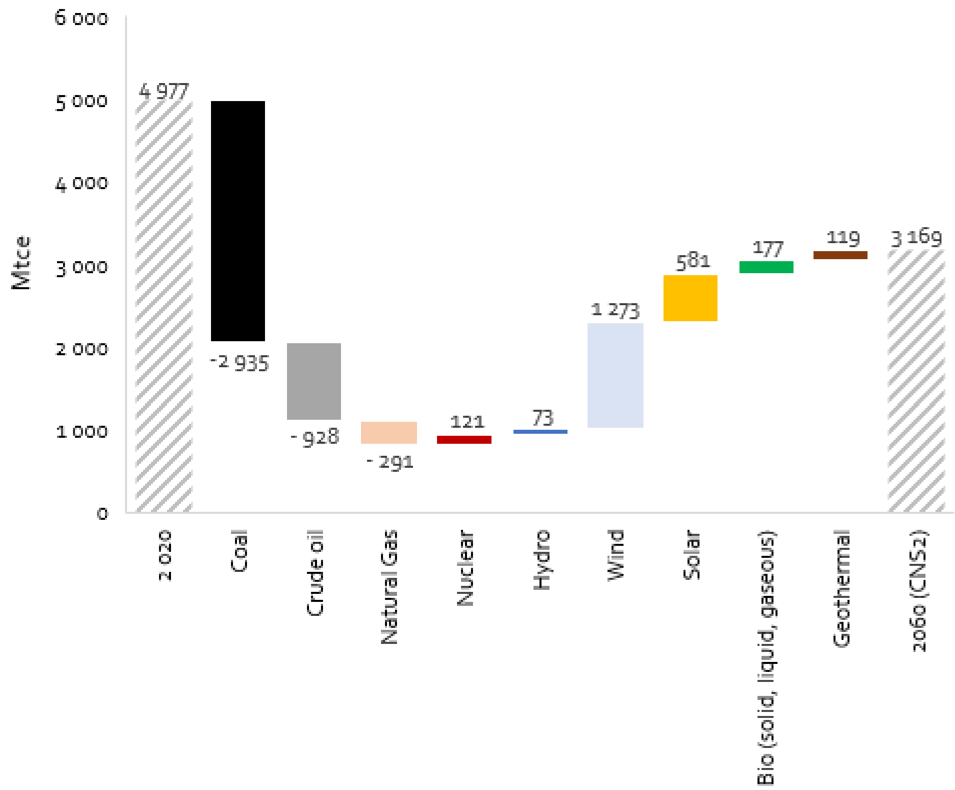


Figure 3-20: by energy type from 2020-2060 in the CNS2



Crude oil demand, led by transportation fuel and industrial chemicals, peaks around 1053 Mtce in the CNS2, and then with greater fuel switching and economic restructuring, falls to 126 Mtce by 2060, compared the level of 1053 Mtce in 2020.

Strong growth of natural gas demand is expected in the mid-term until it peaks before 2040 by 873 Mtce/year in the CNS2. In the BLS2 the peak is 846 Mtce/year in 2039. The momentum is slowly lost over the next two decades as primary consumption declines to 341 Mtce in the BLS2 and 94 Mtce in the CNS2 by 2060.

Figure 3-21: Primary energy demand in BLS2

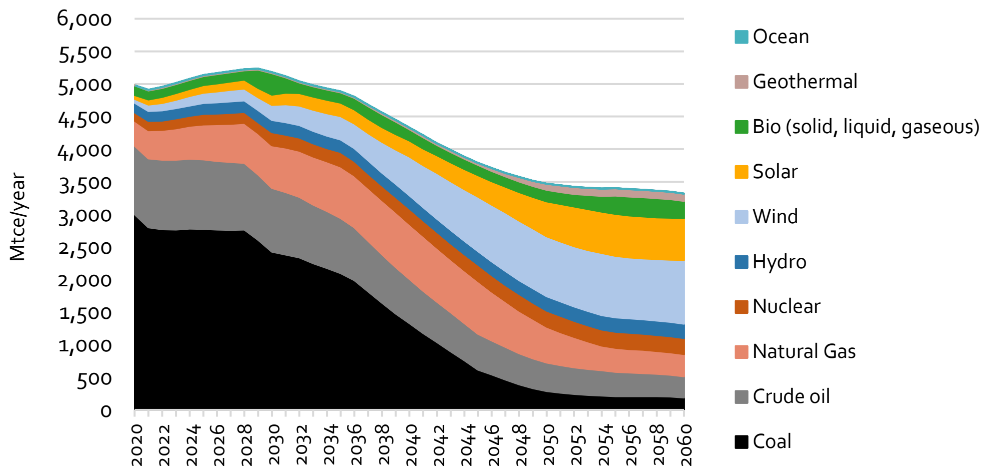


Figure 3-22: Primary energy demand in CNS2

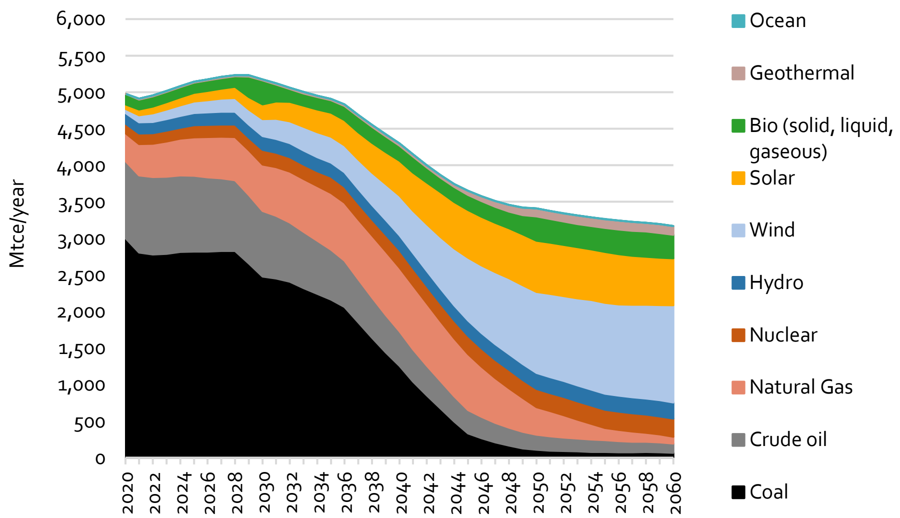
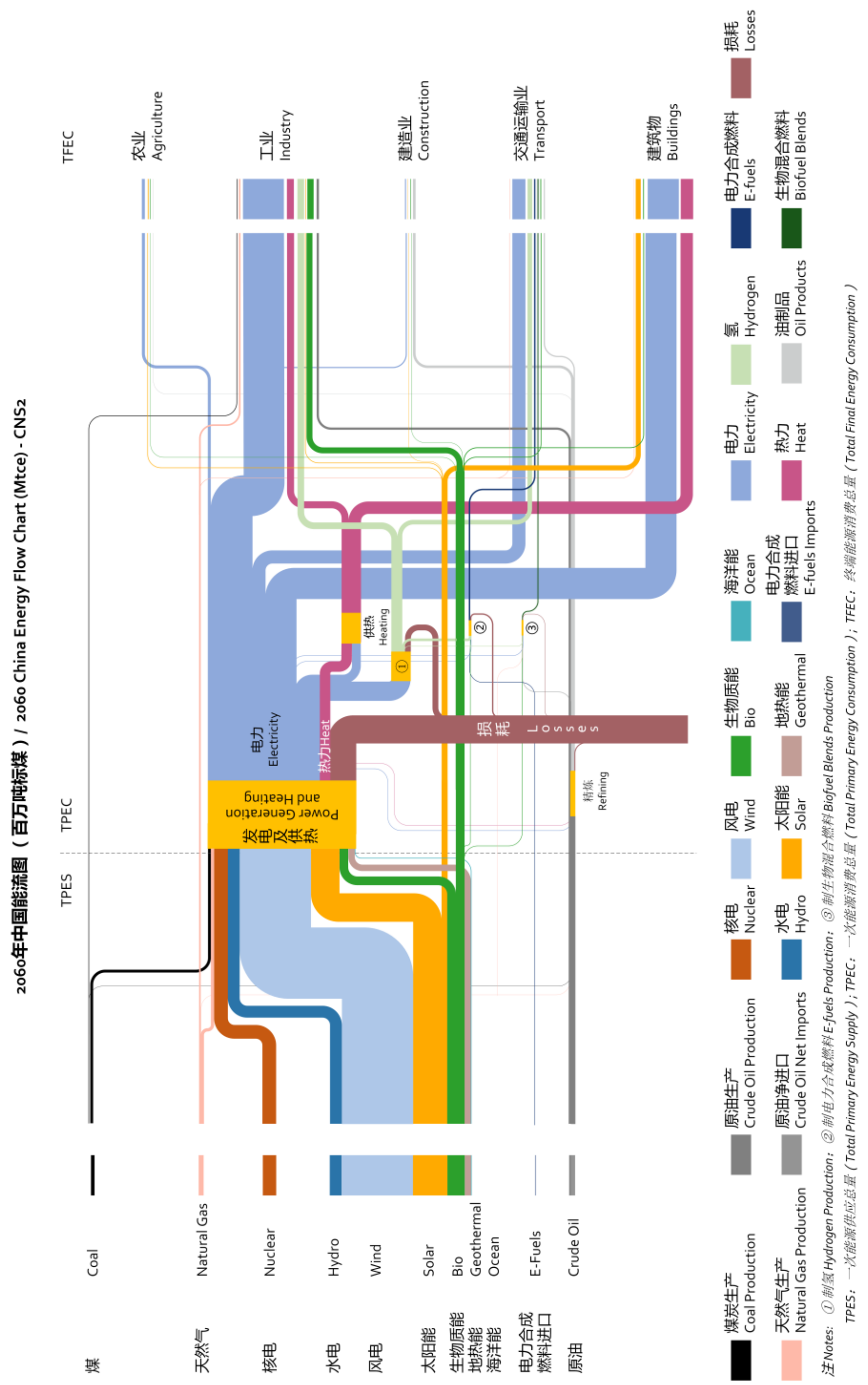


Figure 3-23: 2060 China Energy Flow Chart (Mtce) in CNS2



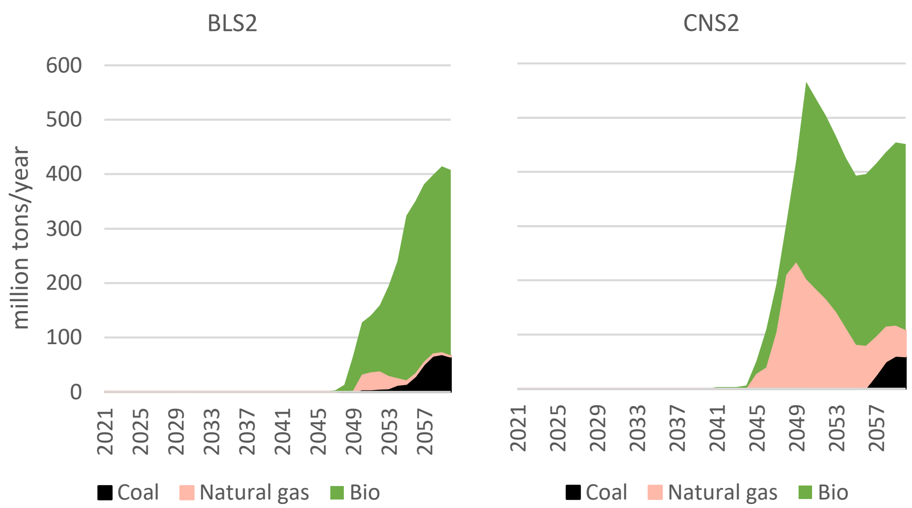
CO_2 emissions from fossil-fuel combustion moves to zero

China's contribution is essential for global efforts to comply with the temperature objectives of the Paris agreement. The CNS2 significantly and responsibly contributes towards the success of this global effort. While the BLS2 is also characterised by an impressive transformation of China's energy system, it doesn't achieve the target of carbon neutrality by 2060, indicating the profound changes needed under the China's 30-60 goals.

Both scenarios show a stable development of CO_2 emissions before 2030. Beyond 2030, CO_2 emissions decline steadily in the BLS2 while the most ambitious approach in the CNS2 leads to a sharper decline in CO_2 emissions from the late 2020's, driven particularly by reductions in CO_2 emissions from coal consumption.

The sharp decline in CO_2 emissions in the CNS2 is owed to the decoupling of energy to CO_2 emissions through electrification, increased RE generation and energy efficiency.

Figure 3-24: CO_2 emissions sequestrated from the power sector in the two scenarios



The key to contributing to global efforts on reducing the global temperatures rise is to decouple economic growth and CO_2 emissions. As shown in Figure 3-25 and Figure 3-26. China's GDP is expected to grow which typically leads to higher energy consumption. However, while initially this led to increased emissions, the decoupling of economic activity and emissions means that the economy has been growing while emissions have been reduced. This has been achieved by introducing energy efficiency measures which enables economic growth with limited increase in energy consumption. This is reflected in reduced energy intensity. Electrification and higher shares of renewable energy in the energy mix can reduce the emission intensity of energy production. Combining reductions in energy intensity and emission intensity can break the curve of energy-related CO_2 emissions, while sustaining growth as seen in Figure 3-25 and Figure 3-26. CO_2

emissions, energy consumption and economic growth does not have to go hand in hand. By following the path of the ambitious, but realistic, CNS2, sustainable economic growth can be maintained while building the ecological civilisation.

Figure 3-25: Kaya identity in the BLS2 scenario relative to 2020

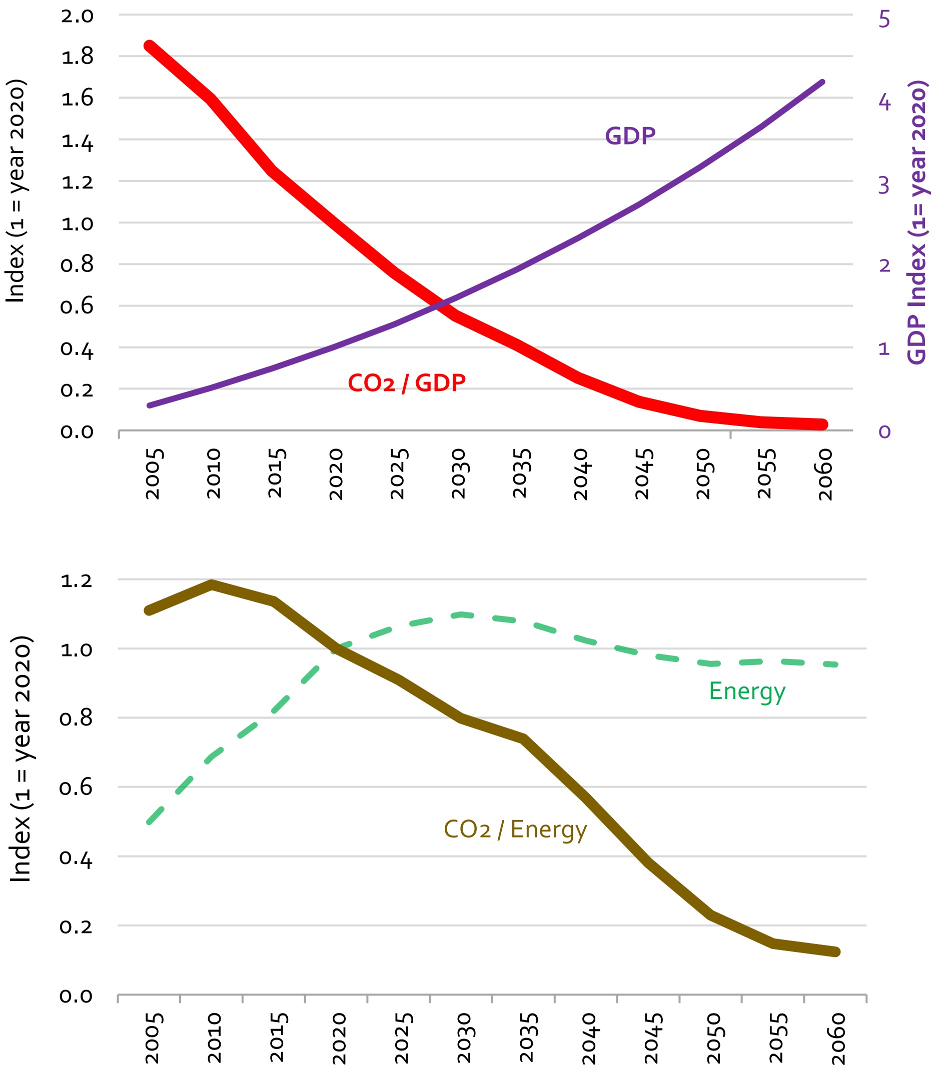
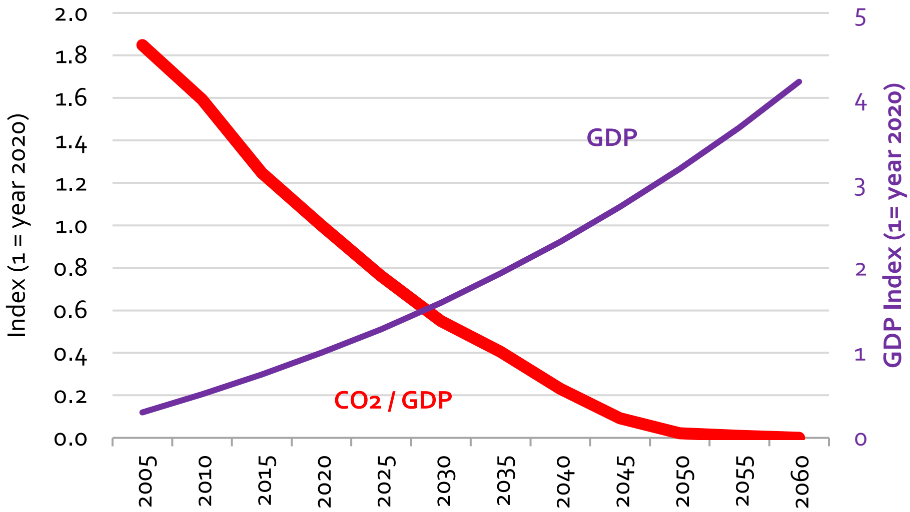
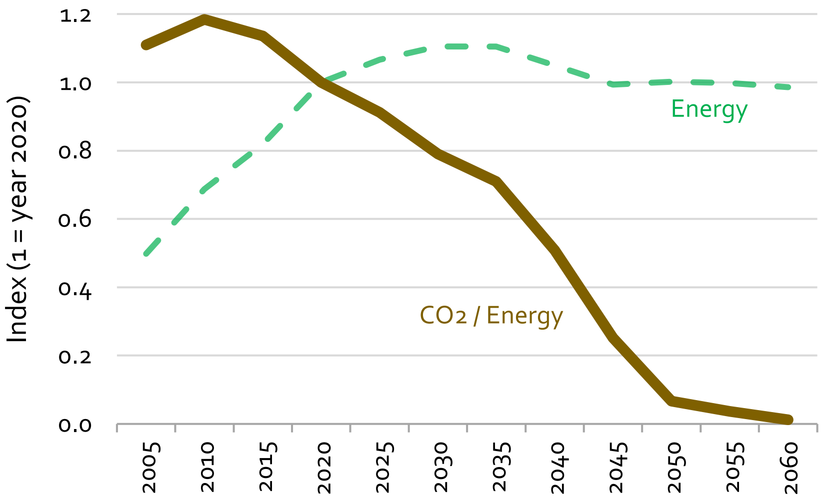


Figure 3-26: Kaya identity in the CNS2 scenario relative to 2020

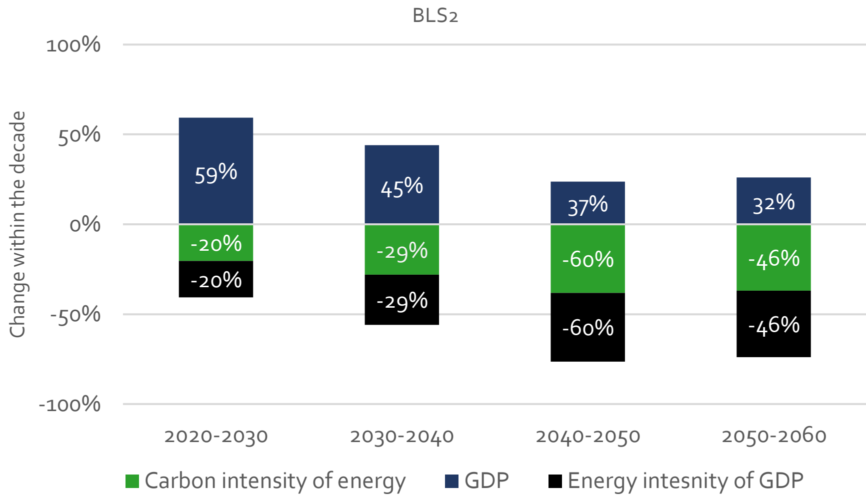


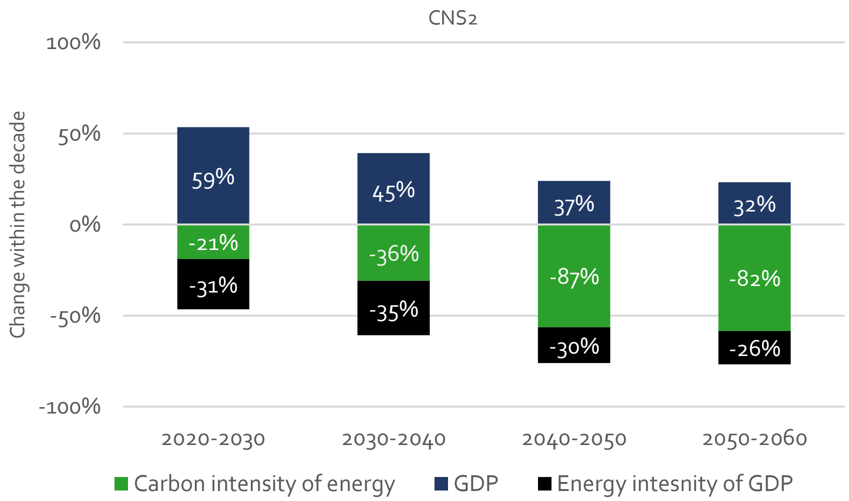


The energy intensity of GDP must be addressed in the coming years if China is to strongly contribute towards the success of the global effort against climate change. Again, energy efficiency is key to breaking the link as it is today. Likewise, the non-renewable share of energy is to be reduced now, and not later, if China is to be a driving force for an ecological civilisation, by bringing down the carbon intensity of the energy consumed.

The figures below, demonstrate that within the next decade, reduction of the energy intensity of GDP is expecting to be equally important to the decarbonisation of energy, in terms of balancing out the additional energy service needs underpinning economic group. In the BLS2, this ratio prevails in the subsequent decades, while decarbonisation of energy, in numerical terms, because an increasing factor in the CNS2.

Figure 3-27: Kaya decomposition of China's emissions.





3.6 General conclusions from the scenario studies

Different methodologies but comparable results

In the CETO 2022, two main scenarios are developed by using different methodologies. Both methodologies use the same overall strategy and overall assumptions as described previously in this chapter.

From an overall perspective, the scenario results from the two methods are very similar. Diving into the details, there are differences in the energy consumption and in the infrastructure development, especially in the power infrastructure. The first method puts more emphasis on solar PV and less on wind power, compared with the second method.

The two methods for the scenario development strengthen the overall conclusions, that it is possible to fulfil China's targets for carbon peak before 2030 and carbon neutrality before 2060 and confirm the overall strategy or combining energy efficiency, electrification, green power, and hydrogen as cross-sector drivers for the energy transformation as described below.

Energy efficiency, electrification, green power, and hydrogen as cross-sector strategies

The CETO scenarios provide a detailed outline of key components which should define China's Energy Transition Strategy and the approach to achieving carbon neutrality.

This relies on four pillars and the last resort:

- **Energy efficiency** improvement on the demand-side is needed to ensure the pace of supply side deployments can keep up and sustain required economic growth.
- **Green energy supply –** technological progress and cost reduction makes RE able to provide the clean energy in bulk, particularly through renewable electricity.
- **Electrification** will support swichting away from fossil fuels in end-use consumption, in conjunction with decarbonisation of the electricity supply.
- **Hydrogen** becomes an important energy carrier, which creates the link between the abundant supply of cheap green electricity, and the hardest to abate sectors. Green hydrogen, combined with captured carbon, allows for the creation of fuels for difficult to abate sectors such as some heavy transport, shipping, and aviation.
- **Sequestration** of CO_2 creates the backstop or last resort option particularly with negative emissions as well as carbon sinks. Negative emissions can compensate for modest level of emissions still in the system in 2060 (e.g., from incomplete capture of fossil plants with CCS).

To achieve carbon neutrality in practice, each of the above pillars relies on the previous. Without energy efficiency, the necessary pace of supply side scale-up of green energy will require excessive amounts of capital and the cost of useful energy services is expecting to be too high. Without green electricity supply, electrification will only serve to move emissions sources from end-use sectors to fossil-fuelled power plants. The hydrogen and PtX pathways are likely the more costly supply side transformations and should therefore mainly serve the harder to transition demand side transformations. Finally, intensive direct and indirect electrification creates opportunities for large-scale electricity consumption, which have significantly higher potential for flexible operation than traditional costly, as well as alternative storage options, e.g., as hydrogen or in consumption side batteries etc. Thereby, electrification process, which requires a green electricity supply, can provide the lynchpin making the necessary final increments of high penetration VRE possible in the power sector.

4 End Use Energy Transformation

4.1 Key messages

- Both scenario sets show that the final energy consumption peaks by 2030 and then keeps falling, pushed by sectoral restructuring, deepen electrification, and improved energy efficiency.
- Buildings is the first sector to reach nearly carbon neutrality, around 2050. It takes longer for industry and transportation to reach net zero carbon emission. The largest challenge lies in heaving industry and long-distance transport sectors. CCUS measures are needed to tackle the left emission in 2060. Without any additional measures, BLS2 shows that there is 1220 Mton CO2 remaining in end-use sectors. This number reduces to 230 Mton in CNS2, 5% of today's level.
- Electrification is the critical measure to decarbonize all the end use sectors. This takes place through technologies like electric cars, buses and trucks on the roads, heat pumps in buildings, and electric furnaces for steel production. In CNS2, electricity and power based alternative fuel accounts for almost 70% of total final energy consumption in 2060. Alongside the growth in the direct use of electricity in end use sectors, there is also a huge increase in the use of electricity for hydrogen production. Beside of 13500 twh of direct electricity by 2060 in end use, there is another 3000 twh electricity demand for hydrogen produced by electrolysis in transformation.
- In industry, most of the emissions reductions are delivered through energy and materials efficiency improvements, electrification of heat, and fuel switching to hydrogen, solar thermal, geothermal and bioenergy. The phase-down of coal in industry is expecting to be through the transition of steelmaking and coal chemical industries. In CNS2, in order to reach carbon neutrality, China needs to curb its steel production to achieve the carbon neutrality goal, by 2035, the total steel production should decline by 20%, and 2060 by 40%. EAF (electric arc furnace) and DRI (direct reduced iron) eventually replaces the current energy intensive and coke based BF/Bof route. Low carbon hydrogen based green chemical develops in large scale from 2035.
- In transport, the electrification is through the quick penetration of EV in passenger vehicles. By 2035, the market share of NEV will reach 100%. Heavy trucking, aviation and shipping adopts other strategies due to the difficulty of electrifying. FCVs are the mainstream vehicles in cross trucks, whose market share takes up to 70% in 2050. Aviation relies largely on biofuels and P2X fuels, and ammonia is vital for shipping.
- In buildings, the priority comes to energy efficiency improvement. Even with a large increase in activity, the total energy demand still keeps in a reasonable range. To reach nearly zero carbon emission before 2050, it requires all new buildings fit ultralow low energy building codes before 2040, and all existing building retrofitted to higher building codes before 2035. The outlook also foresee an

enlarged district heating system due to the flexibility it brings through sector coupling. More electricity is expecting to be used to provide district heating via large scale heat pumps and large electric boilers.

4.2 General trend

For the end use sectors, two sets of scenarios are prepared. The first scenario set, BLS1 and CNS1, which mainly based on the statistic convention from China's current official energy statistics system[33]. This scenario set uses a heuristic approach based on previous modelling studies, including the 2050 High RE Share Scenario analysis, the Reinventing Fire China study, and the various China RE Outlook scenario analyses. Also, the scenarios consider the transformation experiences from pilot provinces and the experienced barriers for a low-carbon energy transformation in China. This set reflects China long term energy consumption trend for all end use sectors, and uses comparative analysis between a baseline scenario (BLS1) and carbon neutrality scenario (CNS1) to identify the indispensable measures in end use sectors for China to achieve carbon neutrality future by 2060.

The other scenario set, BLS2 and CNS2, is of the same research logic. The main difference between the two sets lies in the classification of energy sectors and energy data. There are differences between China's energy statistical system and the international organizations (e.g., IEA and OECD), including different terminology and data collection methods. The second set of Scenarios helps to compare Chinese data with international data. BLS2 and CNS2 calibrate the base year data, regroup the current 7 end use sectors in the energy statistical yearbook into 5 main end use sectors, namely industry, transportation, buildings, agriculture and construction, in order to making the data structure more comparable with the international data form. The energy demand in agricultural and construction is very small, compared with the first three sectors. Thus only industry, transportation, buildings are discussed in detail in the following analysis. The data of scenarios are also supplemented with more sources: 1) 110 Mtce heating was added back to buildings, in addition to the current 55 Mtce heating for residential use, according to the Statistical Yearbook of Urban and Rural Construction[34] [35]; 2) 95 Mtce renewables was added back in buildings, Including 70 Mtce biomass [36] and 25 Mtce solar[37].

Meanwhile, to analyse and forecast changes in future final energy demand accurately, we developed the End-use Energy Demand Model (CNREC END-USE) within the overall accounting framework under LEAP (Long-range Energy Alternatives Planning) software. The CNREC END-USE model analyses the final energy demand in 2060 by a bottom-up approach and end-to-upstream analyses. The bottom-up approach in the model sets assumptions in details in different sectors and subsectors individually based on existing statistical or forecasted data, which is then summarised to larger sectors and the entire energy system. Since the parametric assumption, analysis method and analytical focus of different sectors vary due to the difference in the BLS2 and CNS2, the model makes specific analyses on particular problems in all the end use sectors.

The two scenario sets have the same development trend in the final energy consumption, as shown in Figure 4-1 and Figure 4-2. However, BLS2 and CNS2 start with higher final energy consumption in the base year because of the supplemented heating data and renewables. Both scenario sets peak by 2030, then due to the combined effort of close-down of outdated production facilities , energy efficiency improvement and deepened electrification in all end-use sectors, China's final energy consumption is gradually driven down. By 2060, it decreases to 2363 Mtce in BLS1 and 2210 Mtce in CNS1, and to 2874 Mtce in BLS2 and 2689 Mtce in CNS2.

Figure 4-1: the total energy consumption in end-use sectors in both BLS1 and CNS1

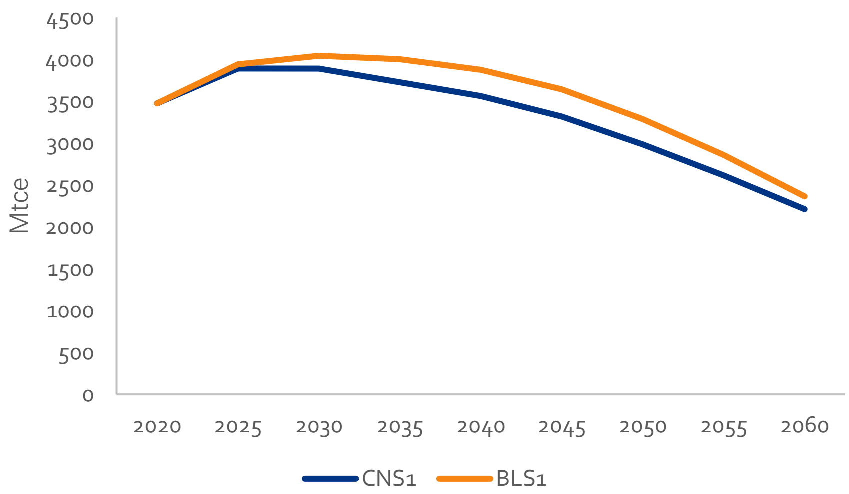
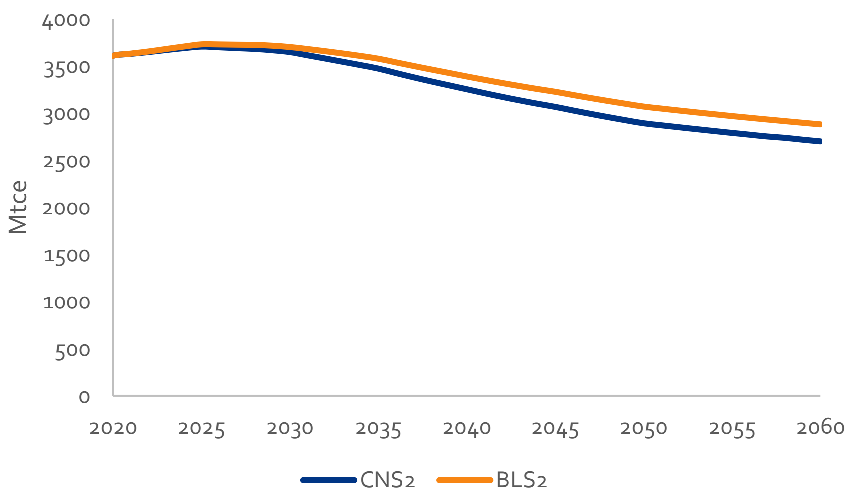


Figure 4-2: the total energy consumption in end-use sectors in both BLS2 and CNS2



Likewise, both scenario sets see cleaner fuel mix in the final energy demand, as shown in Figure 4-3 and Figure 4-4. The shares of coal and coal products in final energy consumption declines from 29% in 2020 to 2% in 2060 in BLS1, and further decrease to zero in 2060 in CNS1. Natural gas decreases from 10% in 2020 to 6% in 2060 in BLS1 and 2% in CNS1. Oil products decline from 25% in 2020 to 11% in 2060 in BLS1 and to 4% in 2060 in CNS1.

For BLS2 and CNS2, the shares of coal decrease from 32% in 2020 to 4% in BLS2 by 2060. Natural gas increases its role in the final energy consumption from 10% in 2019 to 6% in 2060 in BLS2 and 2% in CNS2. The consumption of biofuel in the transport sector increases in absolute terms but retain their proportional role in the final energy mix, while other oil products decline from 10% in 2019 to 11% and 4% in the final energy consumption in BLS2 and CNS2 in 2060. Hydrogen and PtX fuels account for 0.04% in 2019, reaching 17 % in 2060 in the BLS2 and 20% in CNS2.

Figure 4-3: The fuel share of final energy consumption in both BLS1 and CNS1

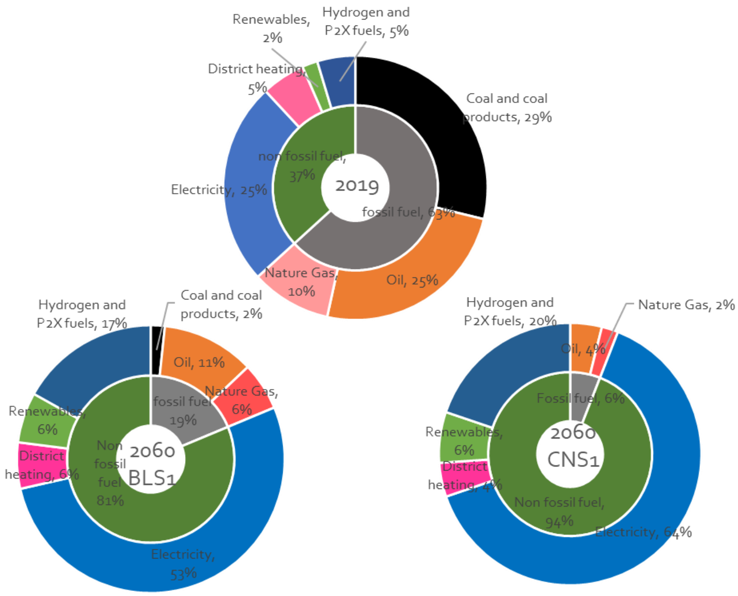
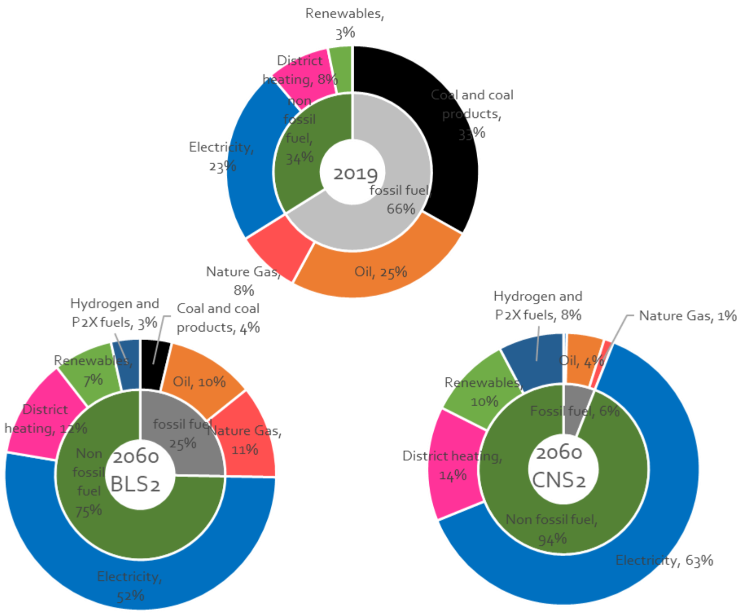


Figure 4-4: the fuel share of the final energy consumption in both BLS2 and CNS2



By 2060, only around 210 million tons of CO2 is left in CNS1 and CNS2, respectively, which is feasible to be further removed by CCS or BECCS units. The CO2 left in 2060 are mainly emitted by oil and natural gas from transportation and industry. On the contract, in both BLS1 and BLS2, around 800-1200 Mtons CO2 are emitted by 2060, even with the help of CCUS method, the carbon neutrality is only to be reached by 2070 or after.

In both sets of Scenarios, in the mid-term, decarbonisation of the industrial sectors is the top priority. Most of carbon emission be reduced along with the phase-down of coal, electrification and fuel switching, however, certain amount of natural gas in industry and oil products in transport is very hard to be replaced by electricity or carbon free fuels. In that sense, CCUS measures are needed to tackle with such emission in 2060 to reach the carbon neutrality.

Figure 4-5: the carbon emission in the final energy consumption in both BLS1 and CNS1

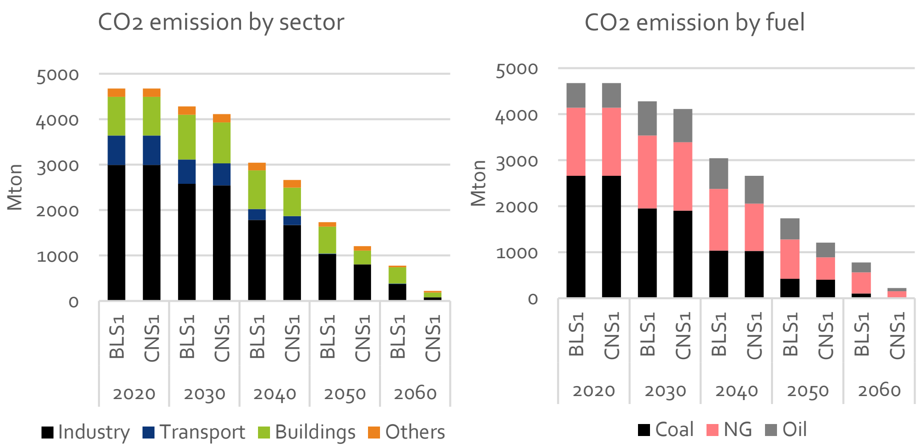
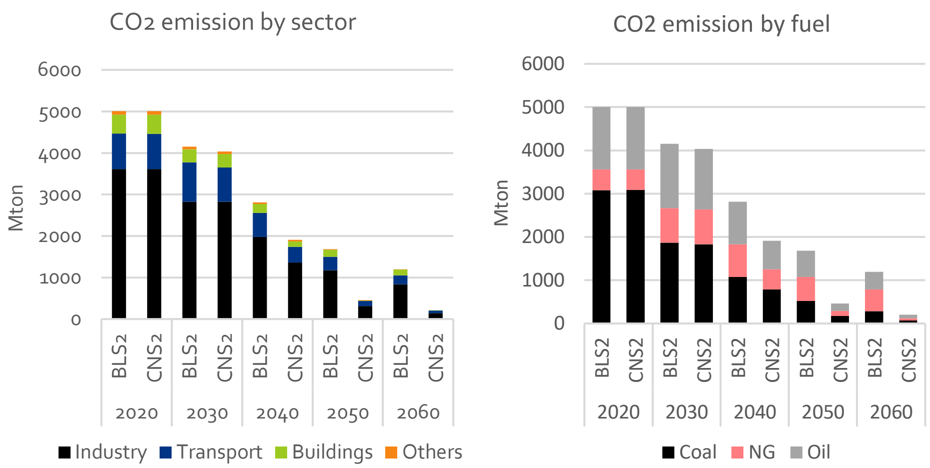


Figure 4-6: the carbon emission in the final energy consumption in both BLS2 and CNS2



The overall electrification rate keep increasing in both scenario sets. See Figure 4-7 and Figure 4-8. The share of electricity as a direct fuel used in final consumption increases from 25% in 2020 to 37% in 2035 and 43% in 2060 in the BLS1. In the CNS1, the share of electricity increase to 39% and 64% in 2035 and 2060, respectively.

In BLS2 and CNS2, the share of electricity as a direct fuel used in final consumption increases from 24% in 2030 to 36% in 2035, and 53% in 2060 in the BLS2. In the CNS2, the share of electricity increase to 40% and 64% in 2035 and 2060, respectively.

BLS2 and CNS2 see that the rapidest electrification happens in transportation. The share of electricity in transport sector grows from today's 3% to 61% in CNS2 by 2060, of which fleet electrification makes the biggest contribution.

In BLS2 and CNS2, we should also be aware that alongside the growth in the direct use of electricity in end use sectors, there is also a huge increase in the use of electricity for hydrogen production. Beside of 13500 TWh of direct electricity by 2060 in end use, there is another 3000 TWh electricity demand for hydrogen produced by electrolysis in transformation. Together with electricity used to provide district heating in the large scale heat pumps, the overall electrification rate of the total society reaches 80% in CNS2 by 2060, while it reaches 78% in CNS1.

Figure 4-7: the electricity share in the final energy consumption in both BLS1 and CNS1

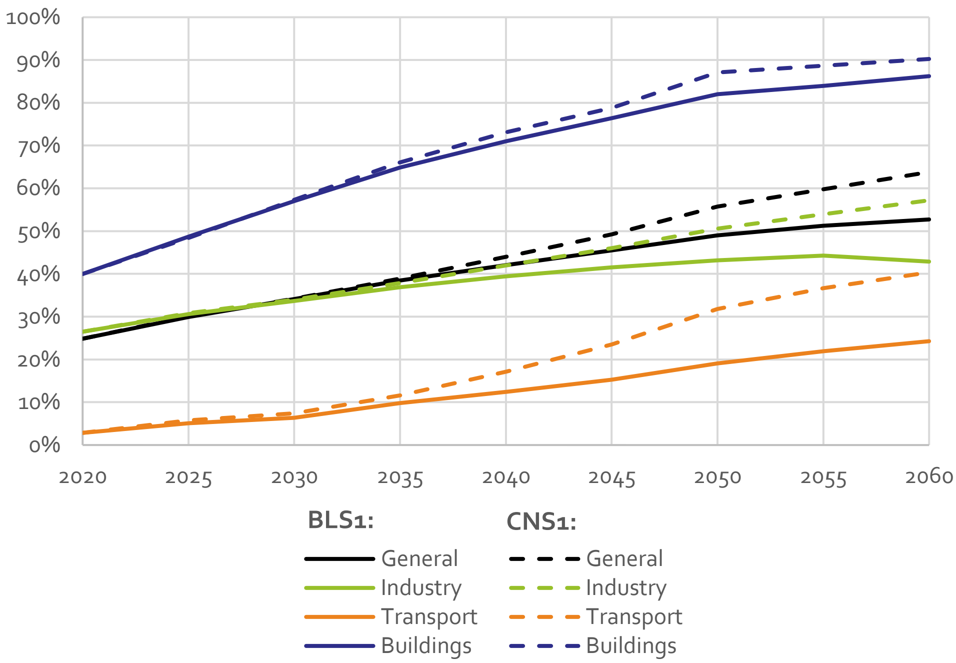
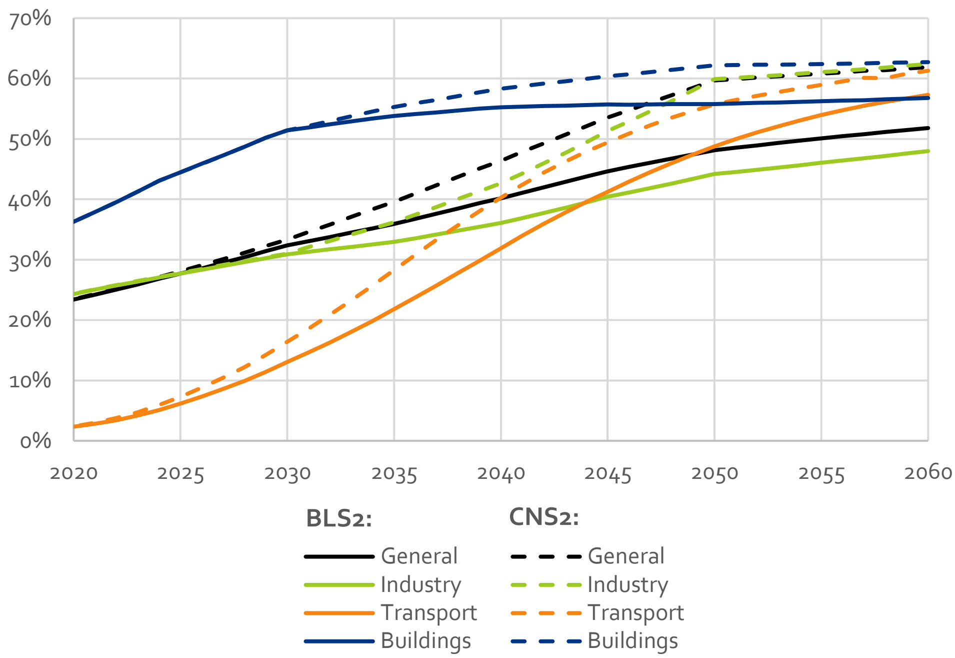


Figure 4-8: the electricity share in the final energy consumption in both BLS2 and CNS2



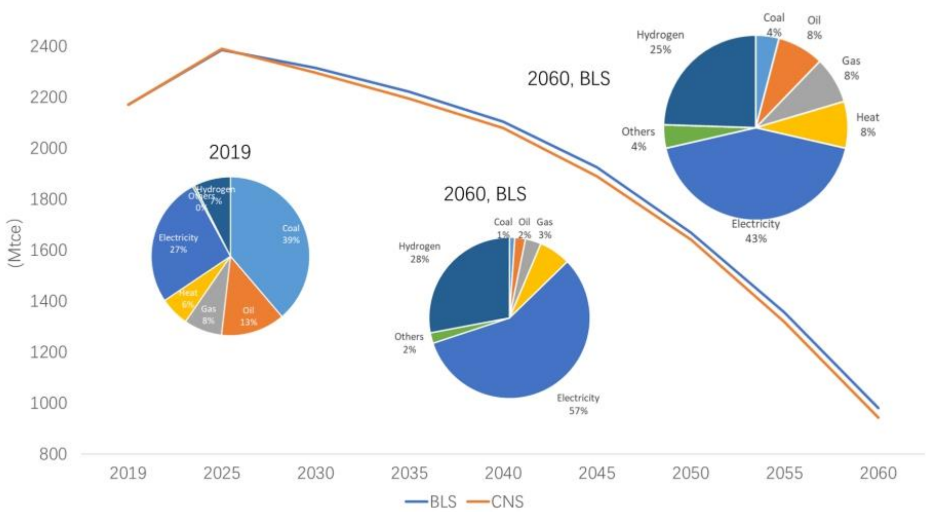
4.3 Industry sector

The final energy consumption in the industry sector peaks around 2030, then decreases constantly in all scenarios. Meanwhile the fuel mix is cleaner. Such transition is through sectoral energy demand rebalancing and restructuring, deepened energy efficiency improvement and electrification. Fuel shifting is the key for industrial decarbonisation, electricity based new technologies, such as EAF and H2-based DRI in steel making as well as green chemicals, contribute with a large portion to the industrial transition.

Energy demand peaks around 2030

The final energy consumption in industry sector grows from 2248 Mtce in 2020 till it peaks around 2390 Mtce in 2025 in both BLS1 and CNS1, then declines by to 980 Mtce and 940 Mtce by 2060 in BLS1 and CNS1, respectively.

Figure 4-9: final energy consumption and fuel shares in industry in both BLS1 and CNS1



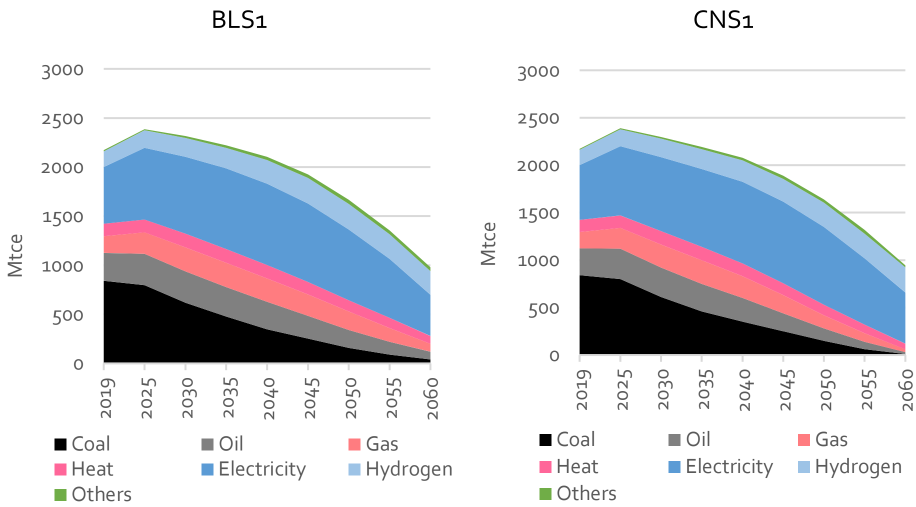
In BLS2 and CNS2, final energy consumption in industry starts to decline since 2020 with the same speed in BLS2 and CNS2. From 2030, the declining rate differs in the two scenarios. by 2060, the industrial energy demand falls to 1340 in BLS2 and to 1220 in CNS2.

From 2020 to 2060, the traditional chemical technologies based on coal and oil gradually phase out the market. Hydrogen and renewables (mainly the biomass) replace the fossil fuel as the chemical feedstock. 2019, 471 Mtce of coal was used for the production of ammonia, methanol, etc., but it is by 2060 only 66 Mtce of coal for non-energy use in BLS2. This number further decline to 10.7 MTCE in CNS2. By 2060, the mainstream non-energy use part is natural gas in BLS2 (with the share of 31%), and hydrogen in CNS2 (with the share of 43%).

Cleaner fuel mix

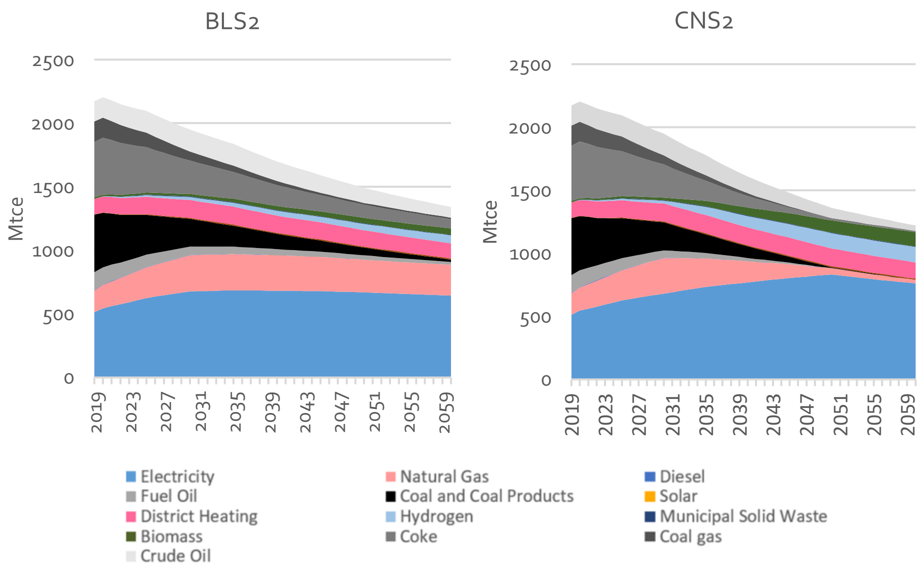
All scenarios see a cleaner fuel mix in industry. Coal consumption shrinks dramatically, from 53% in 2018 to 4.1% in 2060 in the BLS1 and to 1.1% in CNS1. Electricity as a share of final consumption increases from 23% to 43% in the BLS1 and to 57% in CNS1.

Figure 4-10: Future fuel mix in in industrial sector in both BLS1 and CNS1



Coal consumption shrinks dramatically, from 1050 Mtce in 2019 to 103 Mtce in 2060 in the BLS2 and to almost zero Mtce in CNS2, meanwhile, the demand of electricity increases from 513 Mtce from 2019 to 2019 to43 Mtce in the BLS2 and 761MTce in the CNS2. The process of electrification plays a role in modernising industries and increases long-term competitiveness. Industrial electrification benefits from the availability of low-cost decarbonised electricity, while modern industrial processes can supply flexibility for the power system.

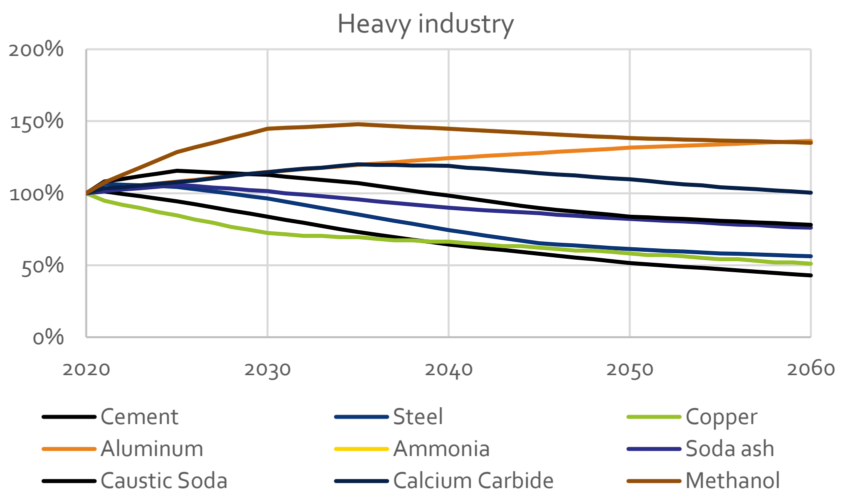
Figure 4-11: Future fuel mix in in industrial sector in both BLS2 and CNS2

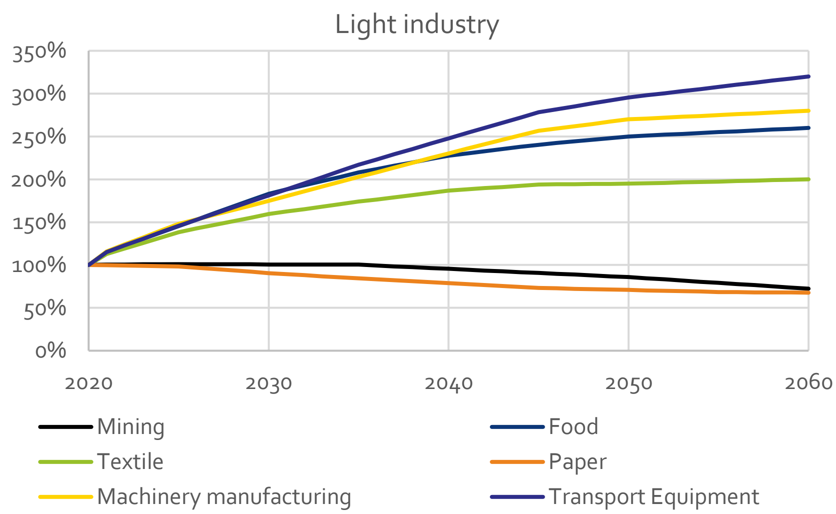


Sectoral energy demand rebalances by industrial restructuring

With excessive capacity and low profit levels, most energy-intensive industries are approaching peak in their market demand in China. The demand of these energy-intensive products such as steel and cement are expected to decline sharply in the future (see Figure 4-12). By 2030, per capita consumption of energy-intensive products such as steel will reach the present average level of developed countries. By 2060, the production of steel shrinks by 44% compared with the current level, cement by 57%, while the output higher-end and more-value-added branches is expected to grow. The output of food industry, electric devices, machinery manufacturing and transport equipment is predicted to grow by 150-220% by 2060.

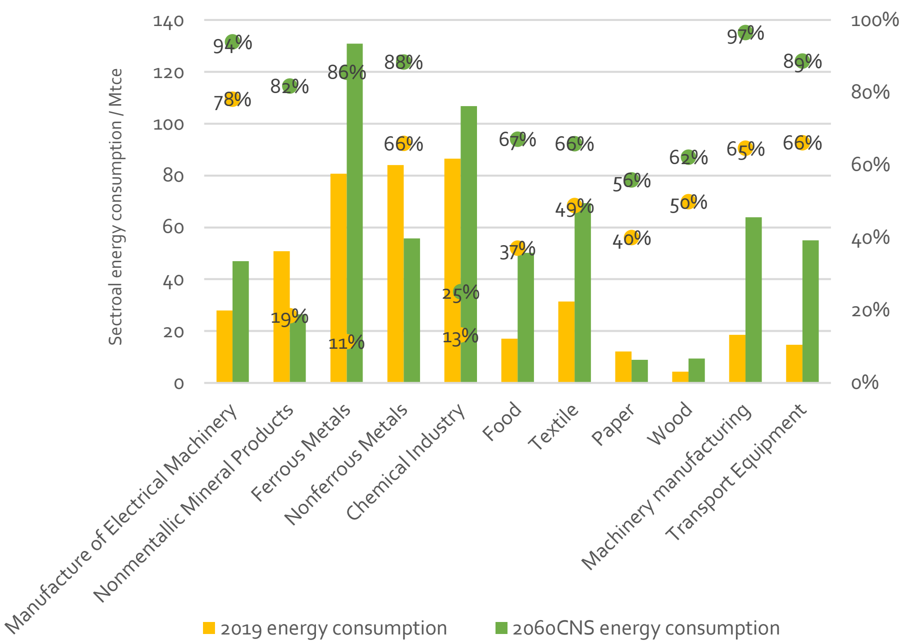
Figure 4-12: Output changes for different industrial branches in both BLS2 and CNS2





In CNS2, the electrification rate of different manufacturing industries rise in varying extent by 2060 (see Figure 4-13) and the general industrial electrification rate In CNS2 eventually reaches 63%. The most rapid electrification happens in ferrous metals.

Figure 4-13: Energy consumption and electricity share in different sectors in CNS2 by 2060

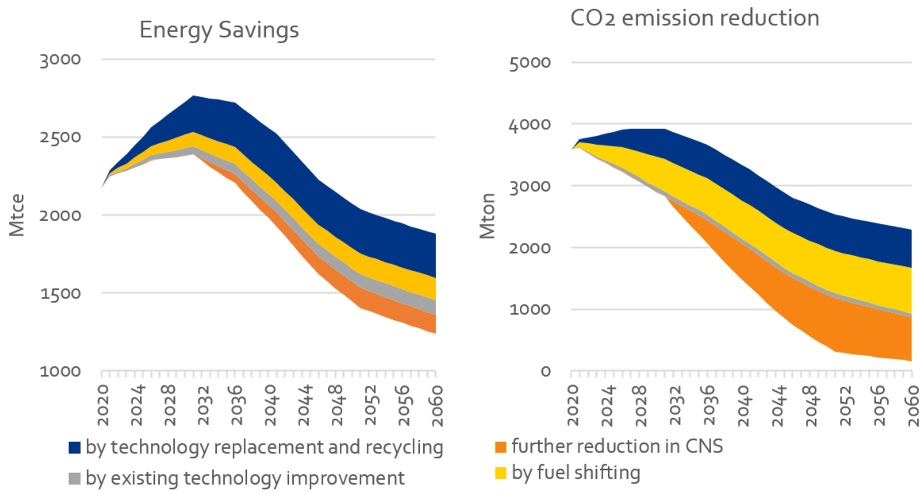


Fuel shifting is the key for industrial decarbonisation

In the BLS2 and CNS2, we have employed the useful energy intensity method to analyse the industrial energy saving potentials and found that the industrial energy saving potential is mainly composed by three parts:1) Energy saved by technology replacement, such as hydrogen based chemical technologies replace the current coal based chemical production, 2)Energy saved by fuel shifting, such as the current coal boiler shifts to more efficient electric boiler, and 3) Improvement of existing technology.

Figure 4-14 shows how these different steps contribute to the total industrial energy saving and carbon emission reduction. Future technology replacement contributes most to the energy saving, by which 280 Mtce energy could be saved in 2060, accounting almost 13% of today's industrial energy consumption. And fuel shifting contributes most to emission reduction. Deepened measures in CNS is crucial to help China transit from BLS to a near net emission in industry.

Figure 4-14: energy saving and emission reduction by multiple measures in both BLS2 and CNS2



Future of steelmaking

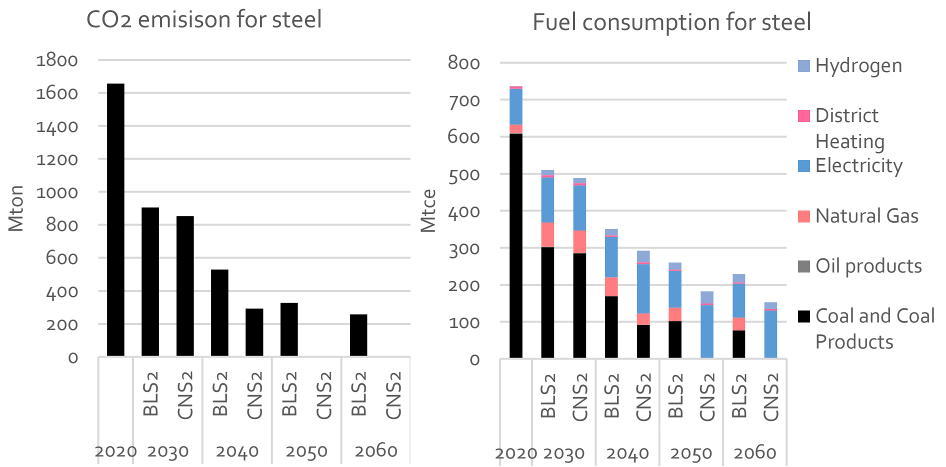
Iron and steel making serves as the core pillar of industrialization and provides material backbone for the national economic development. It is also the largest producer of greenhouse gases in China, emitting 15% of the country's total CO_2. At present, nearly 90% of China's steel comes from coal-based Bf/Bof route, which takes coke as a reducing agent and causes massive carbon dioxide emissions. The future solution to decarbonize steelmaking process can be divided into two categories: 1) increase the share of scraps-based electric arc furnace route, 2) introduce hydrogen-based direct reduction methods, and including using hydrogen to replace coke in the current Bf/Bof route, and also the H_2-based shaft furnace direct reduction.

We see the EAF and H_2-based DRI either in a shaft furnace or a fluidized bed as the final solutions to produce carbon-neutral steel. But the prerequisite is to secure enough steel scrap for recycling and sufficient H_2 which comes from low cost green electricity.

We have designed different pathways development for steel making the two scenarios. In BLS, scrap-based EAF steel share increases from the current 15% to around 50% in the BLS, and further to a higher level in CNS; the share of hydrogen based DRI steel increases to 25% in BLS, but in CNS, it peaks around 2050 with 33% then declines to 20% due to the overwhelming development of EAF route; the traditional Bf/Bof route will be improved, switching the reducing agent from Coke to hydrogen, but the share of this route will keep dropping, due to its higher energy intensity.

With the promotion of electricity or hydrogen based route, the future steeling making will be more energy efficient with a cleaner fuel mix. But the effort in BLS is far from to reach a carbon neutral steel making sector. A full transition could only achieved through more ambitious targets. As Figure 4-15 shows, with deeper electrification and employing more hydrogen based technologies, by 2060 all the steelworks become carbon free, with all fuels coming from electricity and hydrogen.

Figure 4-15: Carbon emission and fuel consumption for steel making industry in BLS2 and CNS2



Green chemicals: ammonia and methanol

Unlike the other countries using natural gas, China's chemical industry mainly bases on coal. The chemical sector is the second largest industrial energy consumer of coal, behind iron and steel. Of all chemicals, coal based ammonia and methanol production are the major CO2 emission process contributors in China's coal chemical sector.

The carbon emissions of ammonia and methanol productions mainly come from the hydrogen production by reacting coal with oxygen and steam under high heat and pressure. It is estimated that, 1 ton of synthetic ammonia emits about 4.9 tons of carbon dioxide during the entire life cycle, and 1 ton of methanol produces about 4.4 tons of carbon dioxide.38 Therefore, a full transition to green hydrogen or biomass could help to move industrial chemicals toward net carbon neutral goals.

This study applies different paths for ammonia and methanol development. See Figure 4-16. In BLS, we assume that by 2040, 20% of the total ammonia is provided by hydrogen based technology, and 20% of methanol should be provided by hydrogen and biomass based technologies; by 2060, 40% of both ammonia and methanol should be provided by green technologies. Meanwhile, in CNS, we assumes that by 2040, 40% of the both ammonia and methanol is provided by either hydrogen or biomass, and by 2060, 90% of methanol and 85% of ammonia should be provided by green technologies.

Figure 4-16: routes share for future ammonia and methanol plants in BLS2 and CNS2

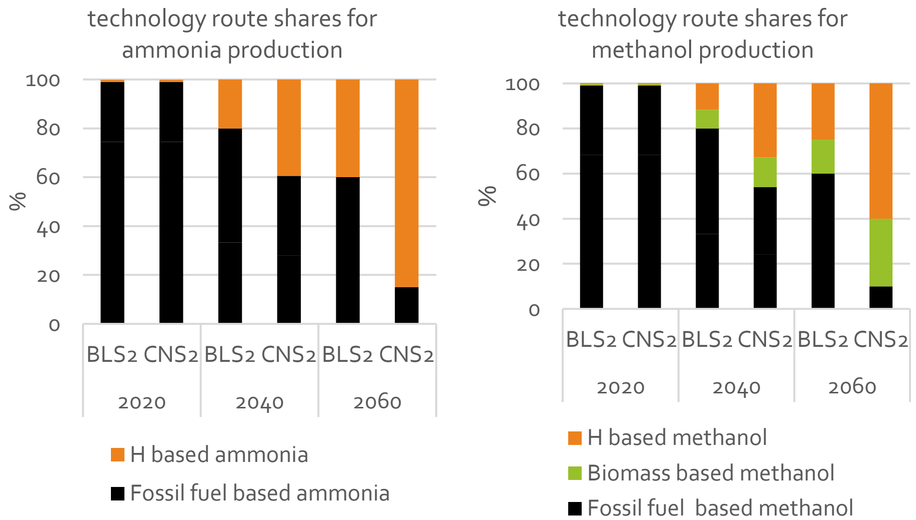


Figure 4-17 and Figure 4-18 show the carbon emission and fuel consumption in ammonia and methanol productions. We can see that with more ambitious targets and deepened decarbonisation measure in CNS, the carbon emission in these two industries by 94-95 % from 2020 to 2060. Natural gas is still used to some extend as feedstock in these two industries, but the emission related to this could be tackled by proper chemical recycling measures.

Figure 4-17: Carbon emission and fuel consumption for ammonia production industry in different scenarios

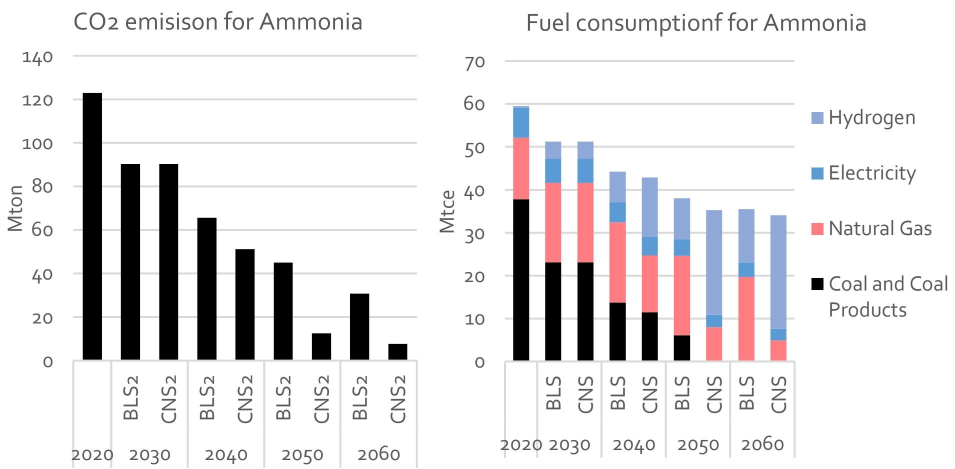
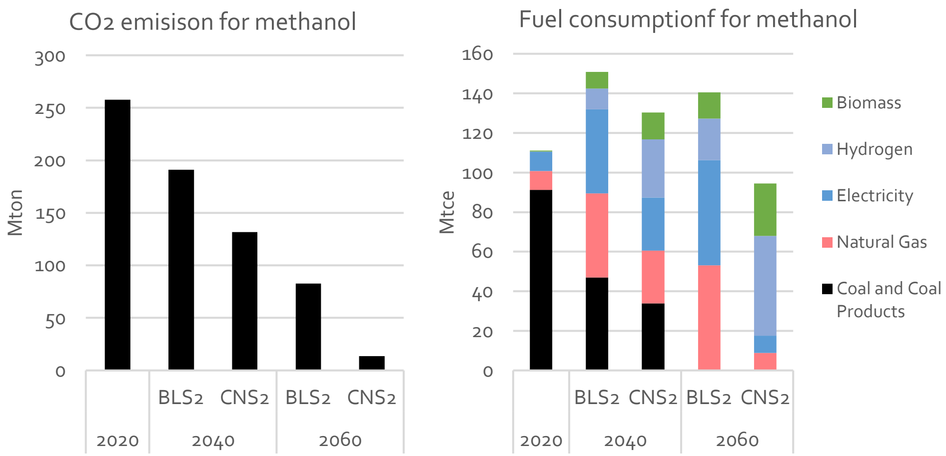


Figure 4-18: Carbon emission and fuel consumption for methanol production in BLS2 and CNS2



4.4 Transport sector

Energy demand

All the scenarios see the final energy consumption in transport sector reachs the peak before 2035.

In BLS1, it peaks around 2035 at 664Mtce, then decreases to 559Mtce by 2060. In CNS1, it peaks earlier around 2030 at 614 Mtce and falls back to 500 Mtce by 2060. See Figure 4-19.

Figure 4-19: The final energy consumption in transportation in BLS1 and CNS1

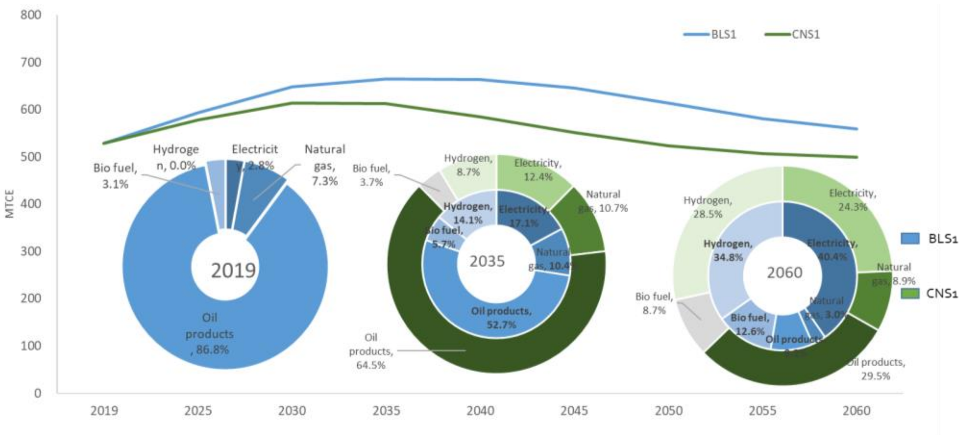
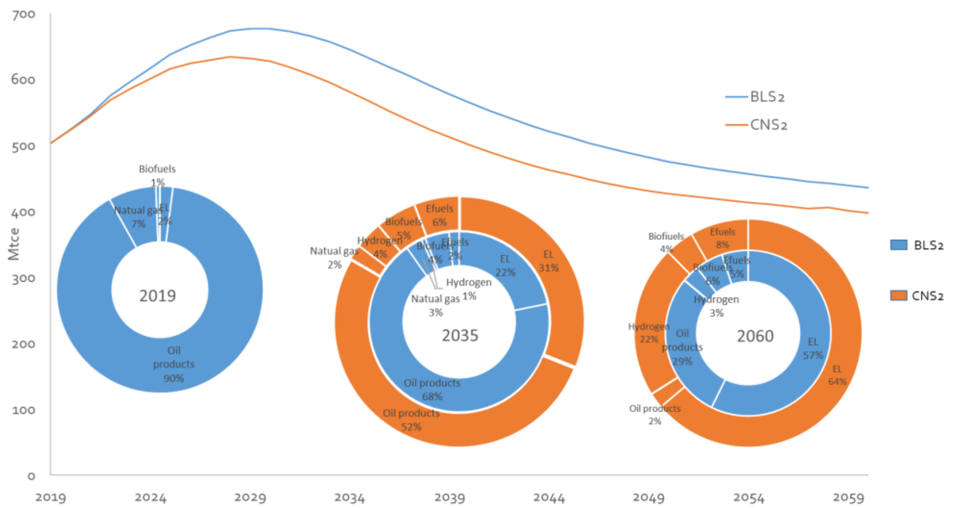


Figure 4-20: The final energy consumption in transportation in BLS2 and CNS2



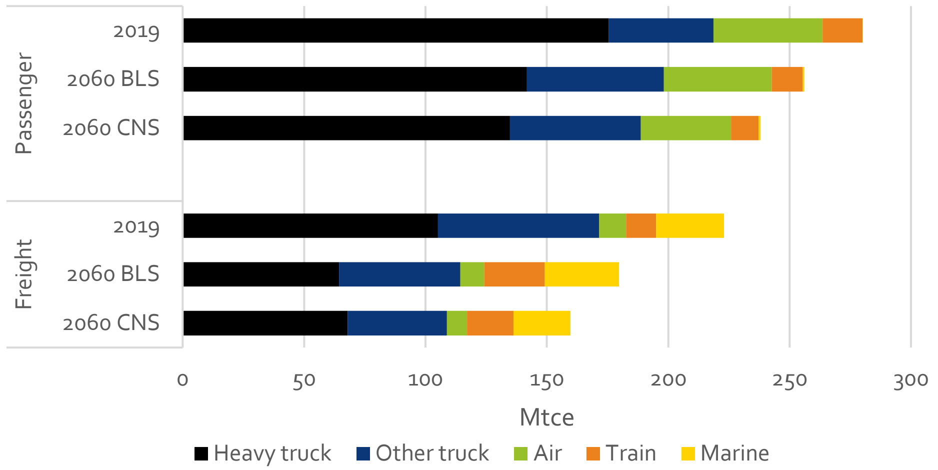
In BLS2, it peaks around 2030 at 677 Mtce, then declines to 436 Mtce by 2060 . In CNS2, it peaks around 2028 at 634 Mtce and falls back to 498 Mtce by 2060. Electricity becomes the bulk of energy consumption after 2035. In CNS, by 2060, the share of electricity increases t 64%, while the oil products shrinks to 2%, the share of biofuel increase to 4%, the rest are hydrogen and other P2X based fuels. See Figure 4-20.

Energy consumption for passenger transport falls from 280 Mtce in 2019 to 256 Mtce in 2060 in BLS2, and to 238 Mtce in CNS2 (Figure 4-21) . Light-duty vehicles' energy consumption still accounts the biggest share in the forecast period, but its energy demand shrinks in both scenarios, duo to the electrification strategy.

Freight transport energy consumption shows a similar trend with the passenger transport. It grows from 238 Mtce in 2018, reaches 350 Mtce and 315 Mtce for 2035 in BLS2 and CNS2 respectively, and then falls to 280 Mtce and 260 Mtce in 2050.

On-road truck will continue to be the major source of freight transportation, the sum all trucks energy consumption accounts 55%-65% of the freight related energy consumption. Heavy trucks see its share increasing yearly, while the light trucks have a gradual decline. The proportion of waterways and railway freight transportation shows stable increase, both from 6-7 %in 2018 to 10-11% in 2050.

Figure 4-21: Energy consumption by mode In BLS2BLS2 and CNS2

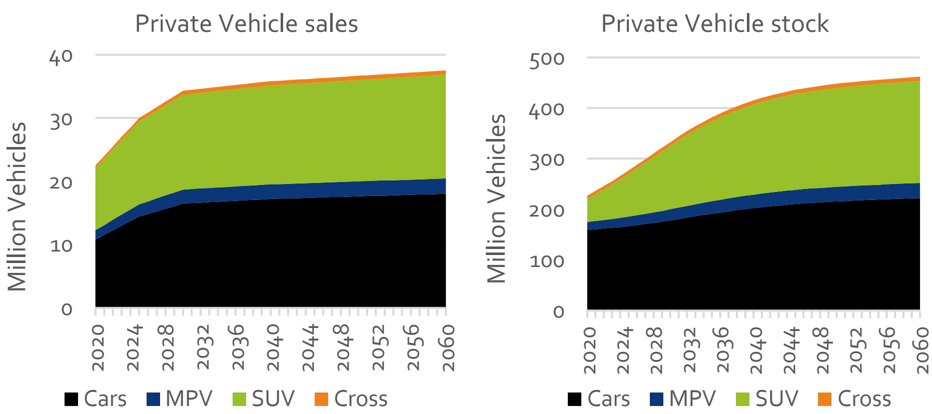


Expansion of all mobility needs causes the demand growth

China's market for private cars has continued its strong growth for many years. China's automobile sales have still ranked the first in the world for 10 consecutive years, with an annual sale of nearly 30 million vehicles, and the national car ownership is above 200 million is the largest private vehicle market in the world. Considering China's low per capita car ownership, and its market stimulating polices, this trend is expected to continue for certain period.

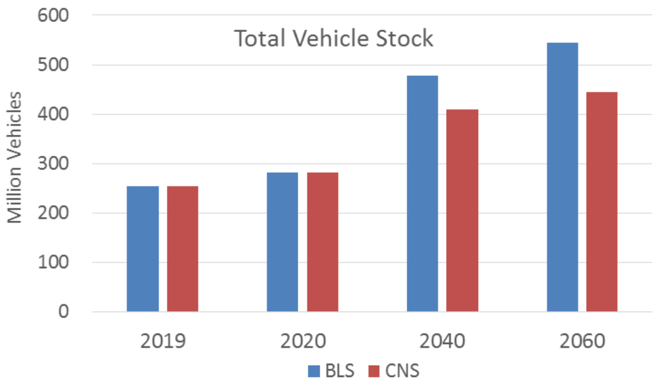
However, in order to curb the fast growing transport energy demand, some control need to be put in to the momentum of ownership growth. In our BLS2 and CNS2, we expect that such rash of car purchase cease by 2030, and afterwards there is only a slow growth in the private vehicle sales. In that way, by 2035, China's passenger car ownership will reach 382 million; by 2060, it will reach 462 million, only double today's level.

Figure 4-22: the sales and stock of future private vehicles in BLS2 and CNS2



Same assumption happens in BLS1 and CNS1. With certain control, the car stock is expecting to be kept within 440-540 million. See Figure 4-23.

Figure 4-23: the stock of future private cars in BLS1 and CNS1



Encourage to take rail for personal travel

Non-road transportation, especially the passenger flights increases rapidly throughout the forecast period. With higher affluence, the Chinese population will travel as much as North Americans and Europeans today, both domestically and internationally. Urban station locations, larger luggage capacity and faster check-in process means that high-speed rail competes well with flights well for trips around 800 km, with good infrastructure and good planning. Travelling by rail is expecting to be a better considering the energy efficiency. In both all scenarios, it is encouraged to take railway over airplanes for personal travel. See Figure 4-24.

Figure 4-24: Future growth in China air and rail travel in BLS2 and CNS2

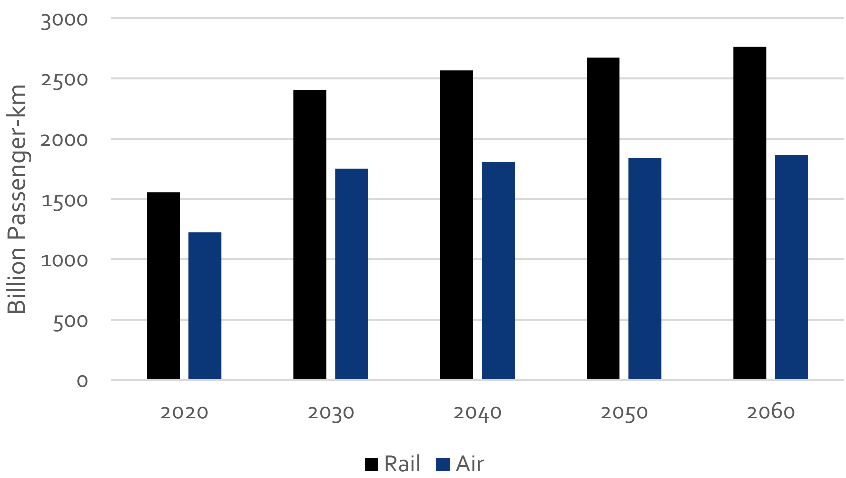
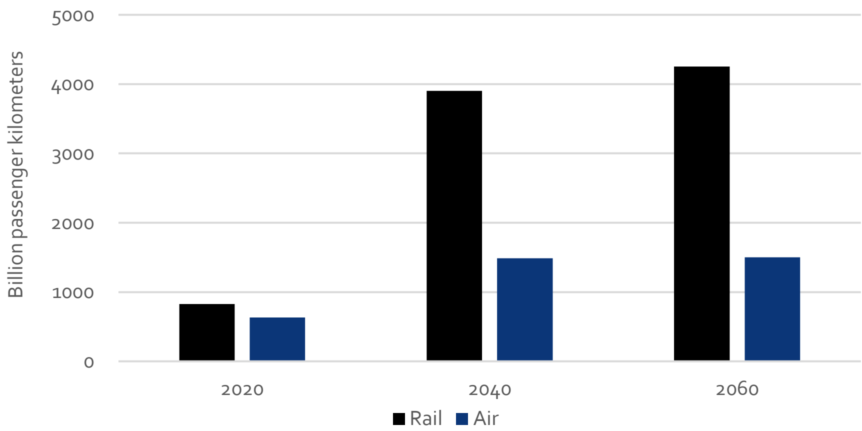


Figure 4-25: Future growth in China air and rail travel in BLS1 and CNS1



Shipping as the dominant mode in non-road freight transport

Freight transport demand relates closely to economic development. By 2060, the total freight transport turnover reaches billion 35000-40000 ton-km, as shown in Figure 4-26 and Figure 4-27. On-road freight only yields limited growth by 2050. Shipping is the dominant freight transport mode. Freight movement shifts to more energy efficient transport modes, such as ships and railway, which grows by 190% and 90% respectively by 2060 compare with 2020 level.

Figure 4-26: Future non-road freight turnover in BLS2 and CNS2

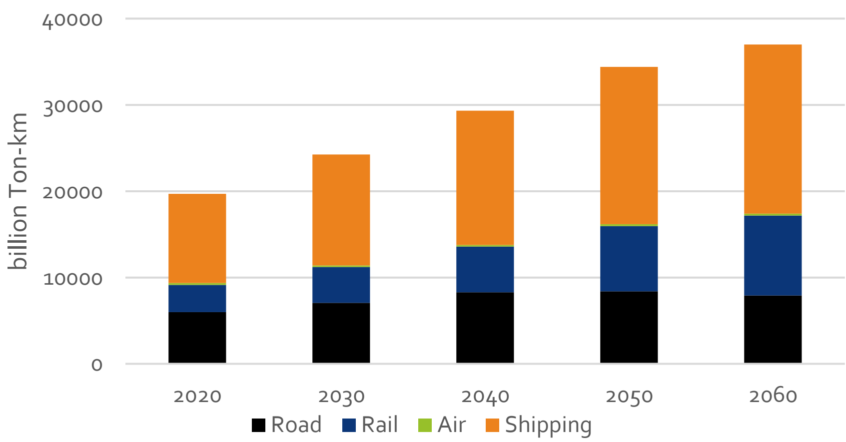
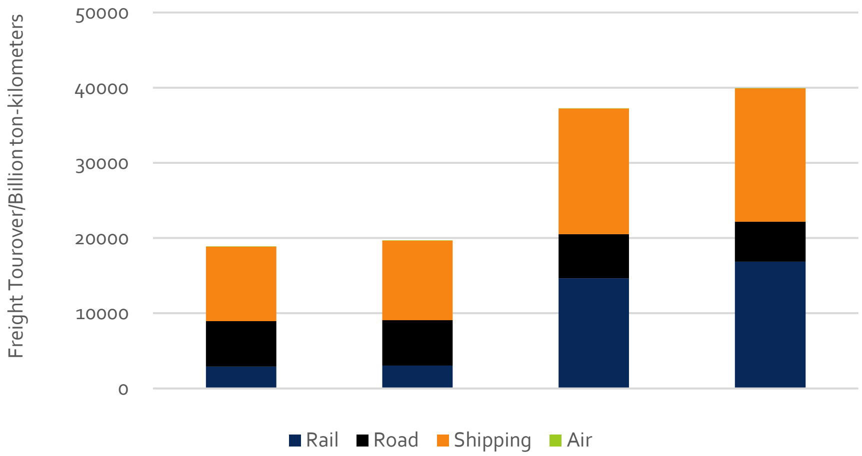


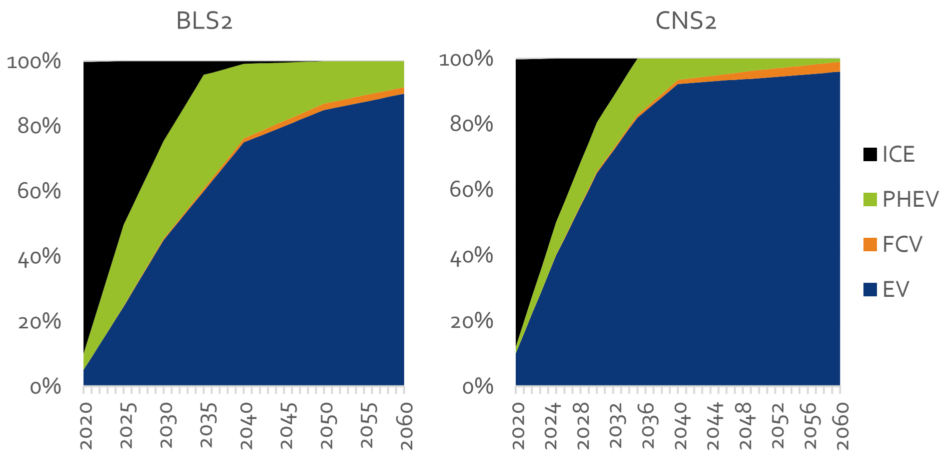
Figure 4-27: Future non-road freight turnover in BLS1 and CNS1



Speed the penetration of electric vehicles

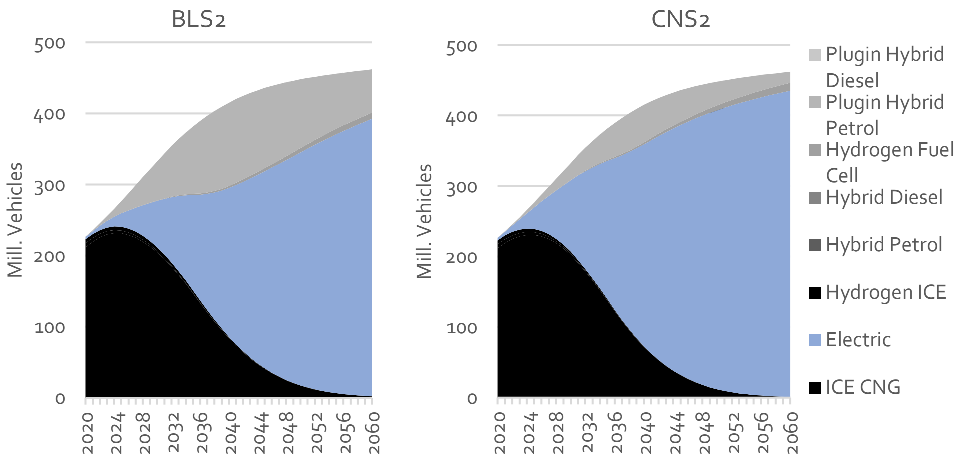
China encourages vehicle owners to buy NEVs already today, with different policies, ranging from easier purchase process without lottery, no smog day limitations on driving to favourable taxes. For China to approach carbon neutrality, these goals and processes needs to be continued and strengthened. Conventional hybrids, where the electric drivetrain serves only as an efficiency measure, is still 100% fuelled by fossil fuels. The carbon neutral scenario suggests removing these from the NEV category, disallowing purchases after 2035. Furthermore, PHEVs, being partly fuelled by fossil and inefficient ICE technology is to be diminished as soon as possible. By utilising mostly BEVs and (to a lesser extent) FCVs, China will gain high energy savings by increased motor efficiency alone.

Figure 4-28: the future market share of light duty vehicles in BLS2 and CNS2



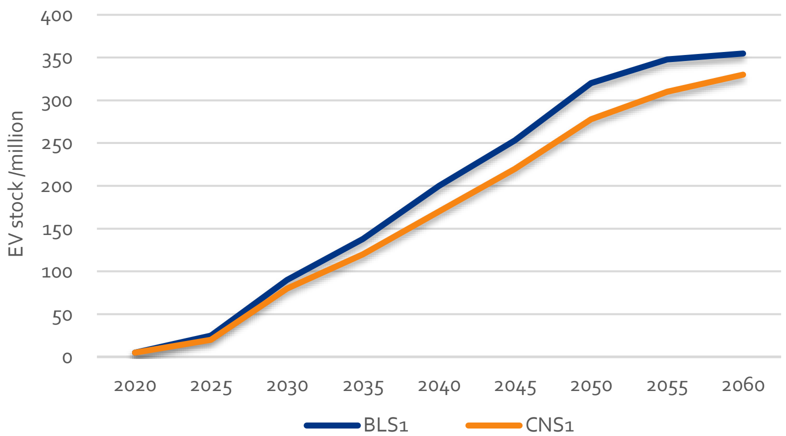
With such promotion policy, by 2060, all of the cars on road is expecting to be new energy cars, as shown in Figure 4-29, of which 390 million is expecting to be pure EVs in BLS2 and 434 million in CNS2, the rest is expecting to be plugin hybrid cars.

Figure 4-29: the future electric vehicles stock by type in BLS2 and CNS2



Same policy assumption happens in the expert judgements. In both BLS1, it is expected to have 330 million EVs on road in BLS1 by 2060, and 354 million in CNS1.

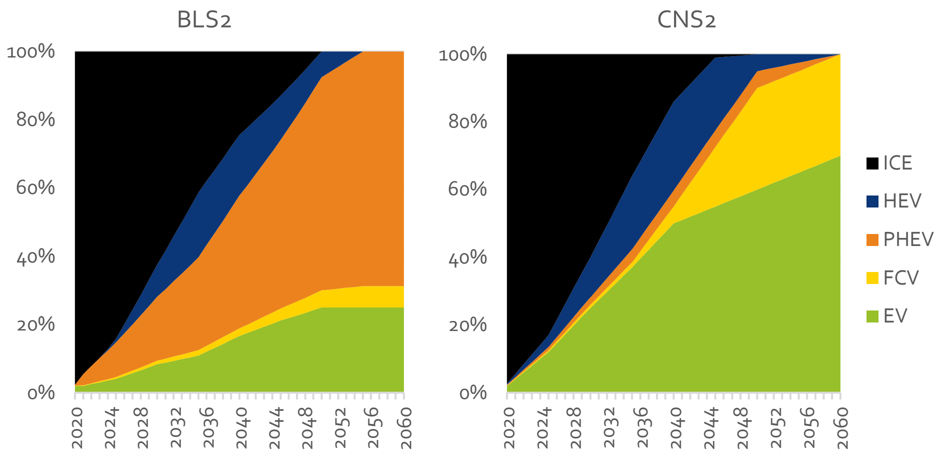
Figure 4-30: the future electric Vehicles stock in BLS1 and CNS1



Freight road vehicles similarly see developments towards using greener fuels in China. The fuels to use however, depends on the utility of the vehicle type.

Normal sized trucks in China, being often utilised in cities are already experiencing a transition towards BEV drivetrain. In the BLS scenarios, PHEVs are to become the majority technology for trucks, with BEV having a smaller share of sales. FCV is not utilised widely in BLS scenario trucks. More ambitious measure shall be implemented to reach carbon neutrality. The sales of BEV trucks will come to dominate the market in the CNS scenario. In short term CNS scenario, regular ICE vehicles are replaced with PHEV counterparts, allowing for much higher efficiencies and clean city driving. Later in the period, FCV trucks will gain traction to fulfil demand where distances are too high for pure BEV.

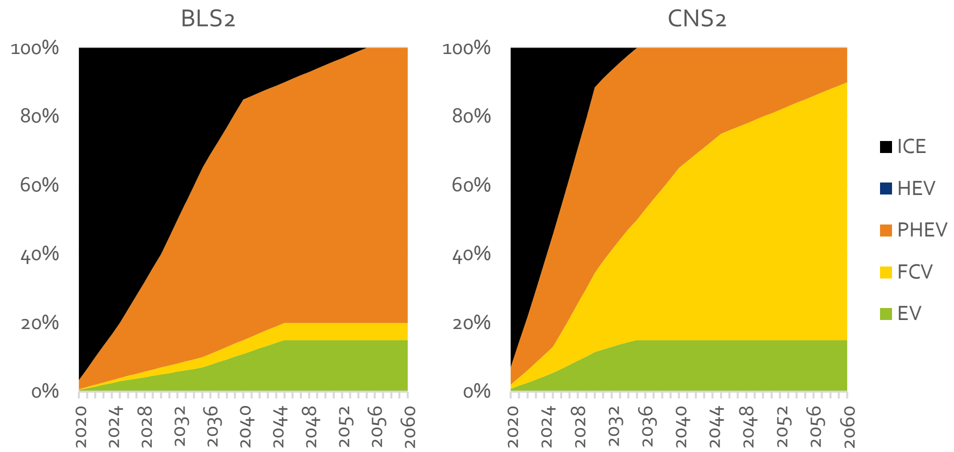
Figure 4-31: The future market share of normal sized trucks in BLS2 and CNS2



Cross trucks, being bigger vehicles often driving between truck depots among regional cities and trucking heavier wares, cannot as easily be fulfilled with BEV technology. BEV vehicles represents a minor share of the sales towards 2060. The CNS2 scenario projects PHEV to replace ICE vehicles in the short term, while this development continues towards 2060 in the CNS2 scenario, making PHEV diesel the dominant technology. The CNS2 long term chooses hydrogen FCV vehicles, as these both offer higher efficiency and clean fuel. This requires investments in new infrastructure, avoided in BLS2. FCV cross trucks is expecting to be the dominant sales technology from 2040 in CNS2.

Semitrailer trucks, specifically used for long distances between cities, relies heavily on fuels allowing long distances and driving hours. The technology choices are similar as for cross trucks, where either PHEV diesel or hydrogen FCV is expecting to be dominant.

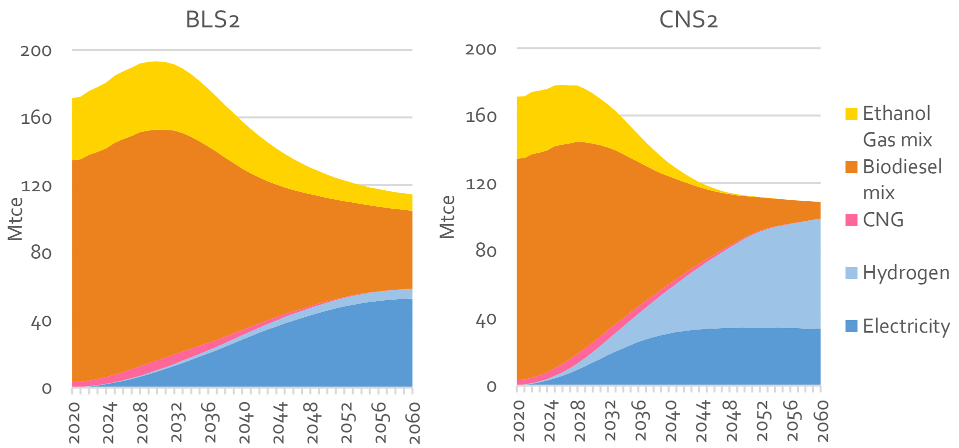
Figure 4-32: The future market share of semitrailer trucks in BLS2 AND CNS2



All trucking vehicle types peak in the short term. Semi-trailer trucks peak currently, while the other types peak around 2030 for both BLS2 and CNS2.

Due to the high efficiency of using PHEV technologies in the BLS2 scenario and the high reliance on hydrogen FCV (having lower efficiency compared to BEV), the total energy demand between scenario is minor. The types of fuels are very different. The BLS2 still relies on fossil fuels, before this is replaced by synthetic and bio based fuels. Hydrogen is expecting to be used more and more after 2035 in CNS2, by 2060, the total hydrogen consumption in trucks will reach 55 Mtce in CNS2.

Figure 4-33: the fuel demand for freight vehicles in BLS2 and CNS2

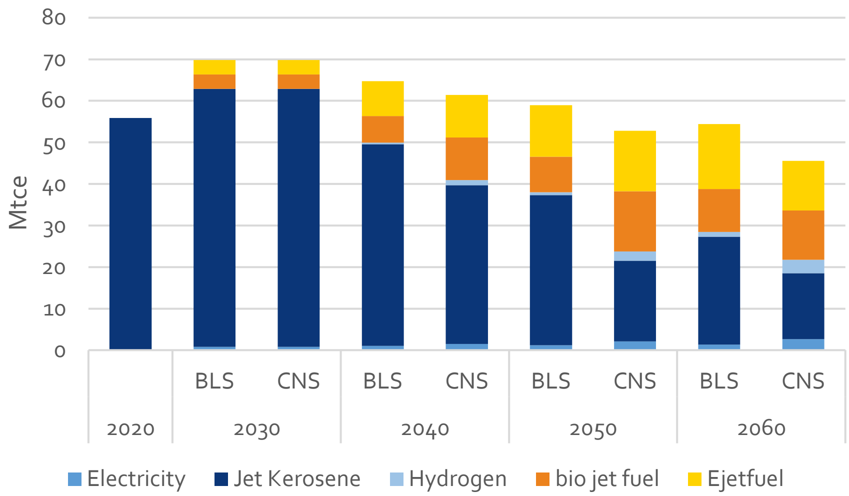


P2X fuels in aviation and shipping

Since the wide adoption of jet engines, the majority fuel for air transport has been jet kerosene. Due to the high requirements for both volumetric and gravimetric energy densities, this is the most difficult sector to transform. New technologies are in early stages, but are assumed to gain footing throughout the period. Airplanes have long lifetimes, why overall change is slow, even with aggressive technologies.

BEV technologies can be used for short-haul flights, where the lesser need for maintenance will make these competitive soon. For longer domestic flights, hydrogen will be the alternative, although this is not adoption in the short term. Aviation are in 2060 still heavily reliant on fossils in 2060, in both scenarios.

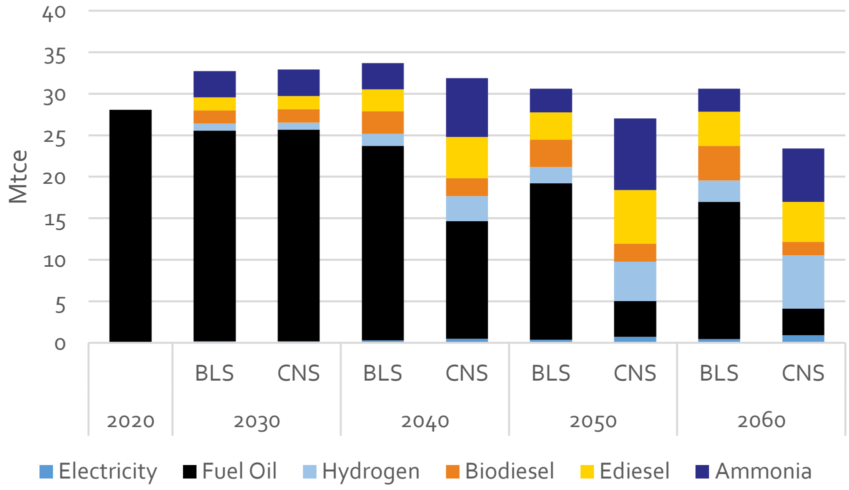
Figure 4-34: the fuel demand for aviation in BLS2 and CNS2

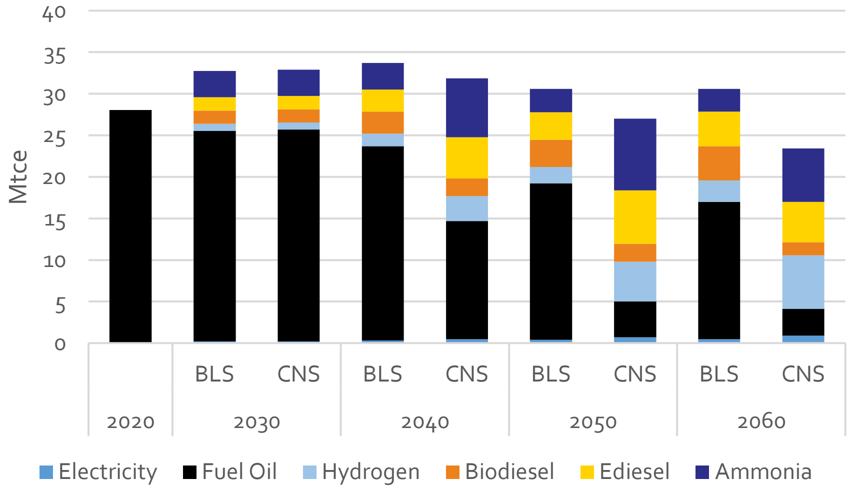


China is the largest shipping nation in the world. Especially freight shipping on the large rivers and internationally consumes vast amounts of oil products. Lesser activity exists for passenger shipping. The shipping continues to expand for freight, with passengers expanding before being replaced by other transport means.

Like aviation, shipping is also hard to transform to achieve net zero, however, most of the emission reduction will be reached by switching to low carbon fuels such as biofuels, hydrogen and ammonia. BEV technology will also be used in a minor share of ships for short distances. E-diesel, made from hydrogen can power older ships, while newer ships will consume ammonia.

Figure 4-35: the fuel demand for shipping in BLS2 and CNS2





Shipping in general sees improvement in drivetrain efficiency, along with technology shifts that reduces energy needs.

Between the scenarios, FCV, ammonia and BEV technologies reduces the demand for fossil fuels by 108 TWh in 2060, almost halving the needs compared to the SPS scenario. Despite this, fossil fuels still retain a large role in shipping by 2060.

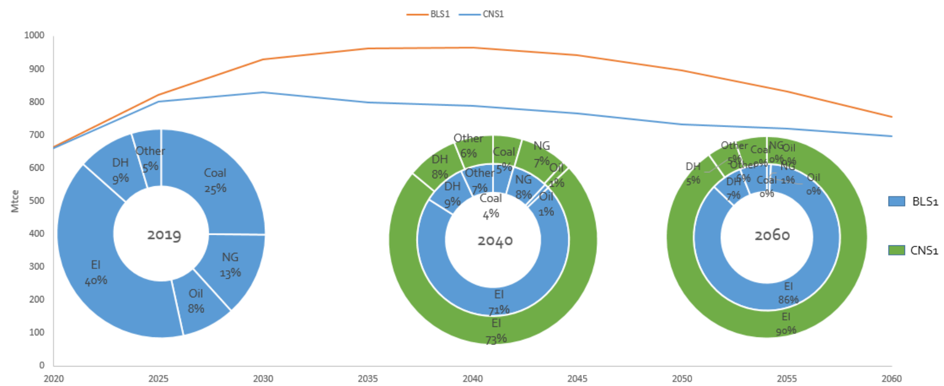
4.5 Building sector

Energy demand

The final energy demand in buildings starts from 633 Mtce in 2019, reaches a peak in 2040 around 965 Mtce, and then declines to 750 Mtce by 2060 in BLS1. In CNS1, the peak comes earlier at 2030 around 830 Mtce, then slightly declines to 700 Mtce by 2060.

In BLS2 and CNS2, because the supplemented heating and renewable data, the final energy demand in buildings starts with a bigger number in 2019 around 728 Mtce. With continuing economic growth, urbanization, and increasing attention to indoor living conditions, China's final energy demand for buildings will grow, reach a peak around 2030 at about 930 Mtce in both BLS2 and CNS2, 26% above the level of 2019, then almost plateau and decline slightly to 2060. Energy fuel mix also changes. In 2060, electricity takes up from 35% to 57% in BLS2, and further to 64% in CNS2, district heating takes up from 22% to 23% in BLS2 and 25% in CNS2. Renewables such as solar and biomass take up from today's 13% down to 10-11%, that is because the utilisation of renewables shifts from low-efficient biomass stoves to cleaner sources. Coal and oil phases down in both BLS2 and CNS2.

Figure 4-36: final energy consumption and fuel shares in buildings in BLS1 and CNS1



In BLS2 and CNS2, we see clean energies meet all of building energy demand growth. By 2060, the building net energy demand growth is about 172 Mtce in CNS2. Electricity, district heating, and renewables contribute the entire growth in final energy demand. The growth in household appliances and office equipment, cooling and lightning are covered by electricity alone. In cooking, energy demand decreases due to more efficient cooking devices and electricity replaces most other cooking fuels. Water heating shows the most growth, growing by a factor of 3.3 times today's level, fuelled by all three clean energies, in which renewable energy is the biggest share. Heating demand decreases with improved building efficiency, but the new growth part is fulfilled by district heating, less efficient ways, such as loose coal in rural areas gradually phase out, person electric heating devices in transition areas, are replaced by more efficient individual heat pumps.

Figure 4-37: final energy consumption and fuel shares in buildings in BLS2 and CNS2

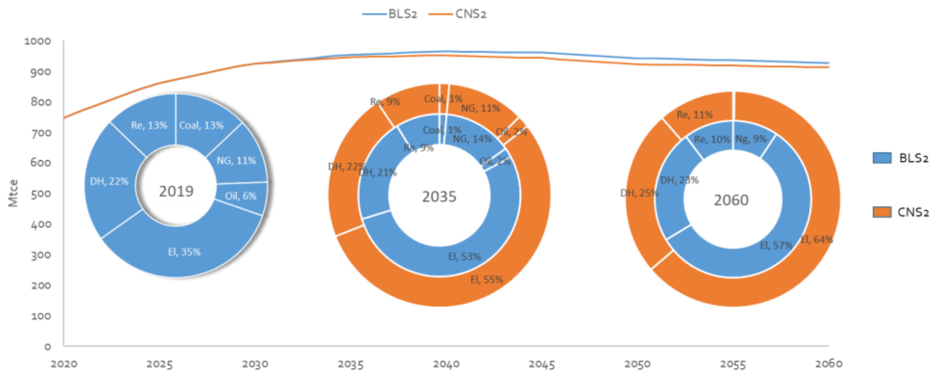
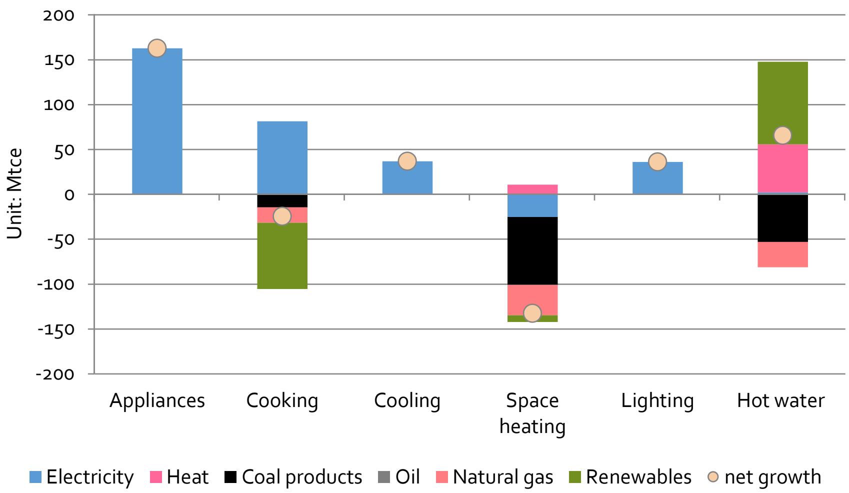


Figure 4-38: Future energy growth and fuel mix in different building services in CNS2 (2019. 2060)



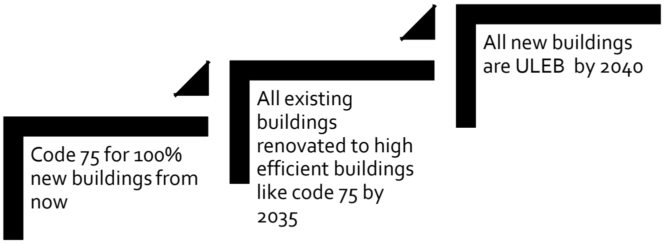
In order to reach the CNS2 and reach a carbon neutrality future in building sector as soon as possible, the following policy guidelines are suggested:

Ultra-Low-Energy Buildings (ULEB), nearly zero energy buildings and more advance building code

It is urgent to promote green buildings from two aspects: 1) retrofit the existing buildings to higher building codes;2), promote ultra-low-energy buildings, nearly zero energy buildings in new buildings.

The CNS2 anticipates that by 2030, 100% of the existing urban residential building will be retrofitted to meet energy saving code 75, and by 2035, 100% of the existing public and commercial buildings will be retrofitted to meet energy saving code 75. 100% of newly-built urban residential buildings and public and commercial buildings will be implemented under energy savings code 85, and by 2040, 100% of existing rural building will be retrofitted to meet energy savings requirements. We anticipate that by 2040 the share of passive building will gradually grow to 80% for newly-built urban residential buildings, and 100% in newly public and commercial buildings.

Figure 4-39: policy measures suggested for building sector



Such measures will significantly lower the heating intensity of all building.

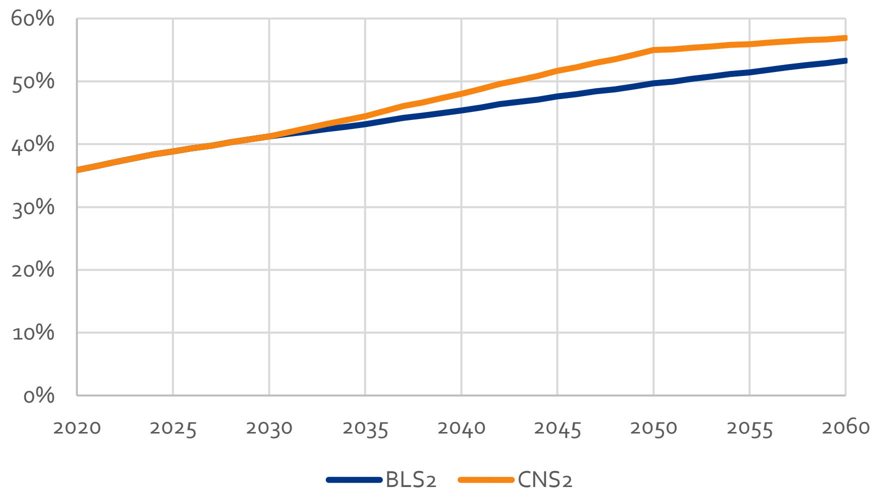
Passive solar buildings in rural area

The current rural low-cost housing is characterised by poor thermal performance. And the current space heating saturation rate is quite low in rural areas compared with urban. But along with economic growth, such saturation rate will soon catch up, and keeping the current rural thermal performance means huge energy waste. Considering that most of rural buildings are independent houses, to promote the passive building design in rural areas will be the most economical way to reach high efficiency and energy saving goals. In order for the passive solar house to achieve house comfort and work better, it is also suggested to combine with auxiliary heat devices such as heat pump to provide heat to maintain the indoor temperature. In CNS2, we foresee that by 2035, 40% of new rural building will be of passive design, and by 2060 all of new building in rural area will be of passive design.

Enlarged district heating system and sector coupling

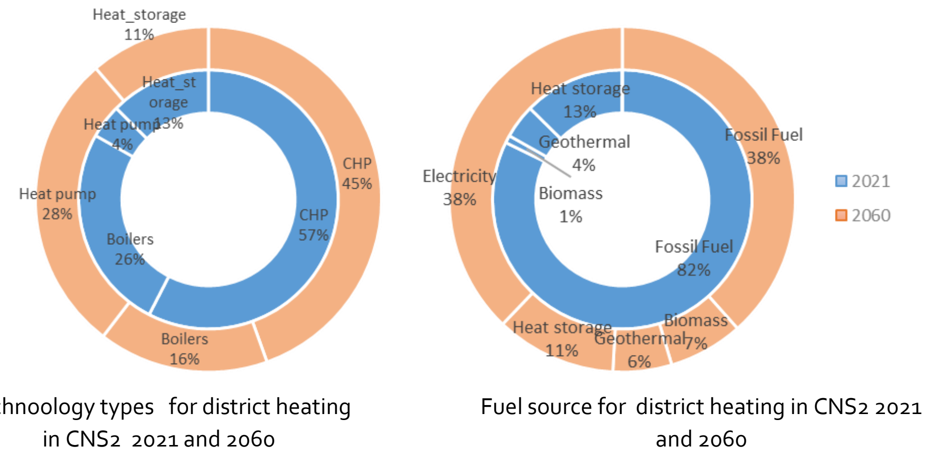
We encourage to further promote the district heating in urban areas. As the one of most economic heating measures, district heating not only owns the flexibility of adapting between multiple clean energy sources, but also could react with power market through sector coupling, and provides additional flexibility in the overall energy system. CNS2 foresees enlarged district heating system.

Figure 4-40: China's floor area in heating area is expecting to be connected to district heating network in BSL2 and CNS2



The modelling results gives us opportunity to dive into the details of the future district heating sources. We see a large potential in the use of heat pumps in the district heating systems of the future. By 2060, heat pumps will replace fossil fuel based boiler and CHP, taking up 28% of all the district heating by 2060, 24% higher than today's level. Fossil fuel as a district heating resource will keep shrinking, from today's 82% to 38% in 2060, and most of the fossil fuel and biomass will be used in CHP left for balancing purpose. Electricity will be the main fuel for heating boilers.

Figure 4-41: fuel sources for future district heating supply in CNS2 by 2060



5 Power sector transformation

5.1 Key messages

Structural transformation of supply and demand

- China’s total electricity consumption will continue to increase with the nation’s continued electrification. In BLS1, total power consumption is 9398 TWh in 2025 and 12485 TWh in 2035. Compared to the 2020 level, power consumption in 2060 increases by 6418 TWh, suggesting a twofold increase in total power consumption from 2020 to 2060. It grows even faster In CNS1 compared the BLS1, with the difference between the two scenarios reaching 2190 TWh in 2035 and 3043 TWh in 2060. This is largely driven by the transportation and building sectors, as well as broader application of power to hydrogen (P2H) technologies.
- To meet the growing electricity demand and the need for accelerating energy transition, an important trend has arisen is shaping China's electricity supply, namely, replacement of fossil fuels, especially coal, with renewable energy sources. In BLS1, in 2025, China's total installed power capacity is projected to reach 2769 GW, of which coal accounts for 42%; and the total power generation capacity installed from non-fossil fuel sources is to reach 1477 GW, accounting for 53% of total installed power capacity.
- In CNS, driven by rapid increases in the shares of power generation capacity installed from non-fossil energy sources, including wind, PV, geothermal and biomass, the share of installed coal-fired power capacity is projected to decrease at a higher rate. By 2060, the share of installed coal-fired power capacity is projected to be only 96 GW in CNS1 and 160 GW in CNS2, taking up a 4% share of total installed power capacity.
- The cost of solar and wind power generation is expected to decline over time, with renewables, mainly wind and solar, accounting for the majority of the electricity supply mix. By around 2030, technical costs of wind and PV power generation is projected to be on par with those of fossil fuels, and in the long run to remain at significantly lower levels than those of fossil fuel generation.

Flexibility and system integration

- In the near to medium term, coal and pumped storage remain the most important flexibility resources in China. By 2035, coal power is expected to basically complete flexibility transformation, with pumped storage capacity being fully developed.
- In the long term, EV smart charging, EV-V2G and electrochemical energy storage have the greatest development potential. By 2050, a relatively complete flexible service system for EVs puts in place, and electrochemical energy storage enters a fast lane of growth after 2050.

- North, Central and East China have the most abundant demand response and energy storage resources, with a combined capacity share of over 60%; South, Northwest and Northeast China have a share of less than 15%.
- Lithium-ion batteries are in the medium to long-term expected to be the cheapest alternative, and thus are one of the future choices of large-scale storage technology.

Power market reform

- Following China's pledge to be carbon neutrality, some noticeable advances have been made in its electricity market reform. The second batch of pilots on electricity spot market was successively launched in six provinces and cities, including Shanghai, Jiangsu, Anhui, Liaoning, Henan, and Hubei. For regions covered by China Southern Power Grid, the nation's first-ever unified regional frequency modulation auxiliary service market system was officially put into operation. A new standalone green power trading pilot programme was introduced under the medium and long-term power trading framework. The nation's first-ever pilot project on market-based distributed power generation trading was successfully connected to the grid. On-grid tariffs for all coal-fired power generation have been liberalised in an orderly manner.
- The electricity market reform is deemed as one of the most significant measures to realize the CNS of this Outlook, whereas carbon pricing bolstered by market mechanisms acts as a key enabler for power sector decarbonisation.
- The next step of the electricity market reform is to focus on creating a nationwide market integrating a higher proportion of renewable energy.

Power transmission and grid infrastructure planning

- Commitments to facilitating regional coordination of power sources and loads, and to aligning power grid development with power supply layout, is the key to carbon neutrality by 2060.
- To support growing regional demands and renewable energy integration, there is a need to increase power transmission capacity. Estimation of the EDO model indicates that, by 2060, China needs an additional 627 GW, 894 GW and 593 GW, respectively, of total interprovincial grid capacity within different regions in BLS1, CNS1 and CNS2. The regional power flow is expanded from 760 GW in 2020 to 2681 GW in 2060 in BLS1. The size of overall power transmission in 2060 is more than 4 times in the CNS1 and CNS2, compared to the number in 2020.
- The increasing penetration of renewable energy is set to call for more frequent and larger-scale balancing of regional power, capacitance, and grid. In the medium and long term, China's grid development is targeted at comprehensively building a modern grid system that is economy-friendly, adaptation-friendly, and environment-friendly.

5.2 Structural transformation of electricity supply and demand

Electricity consumption and demand

Power consumption development

China's electricity consumption grows steadily throughout the 2020-2060 period. On one hand, this is to support the economic growth and improvements in quality life. On the other hand, it is driven by electrification of all end-user sectors to achieve a more efficient and clean energy system. Electricity saved through improvements of efficiency also affects the electricity demand. This leads to slower growth of electricity consumption in later stages.

The total electricity consumption increases in both scenarios, corresponding with the continuous electrification in China. In BLS1, the total power consumption increases to 9398 TWh in 2025 and 12485 TWh in 2035. The power consumption in 2060 increases by 6418 TWh as compared to the power consumption in 2020. This means that the overall electricity consumption doubles from 2020 to 2060. The CNS1 and CNS2 has a faster increase compared to BLS1, and the difference between three scenarios reaches 2190 TWh in 2035 and 3043 TWh in 2060. This difference in 2060 is equivalent to 22 % of total power consumption of the BLS1 in 2060.

Table 5-1: Electricity consumption by sector (TWh)

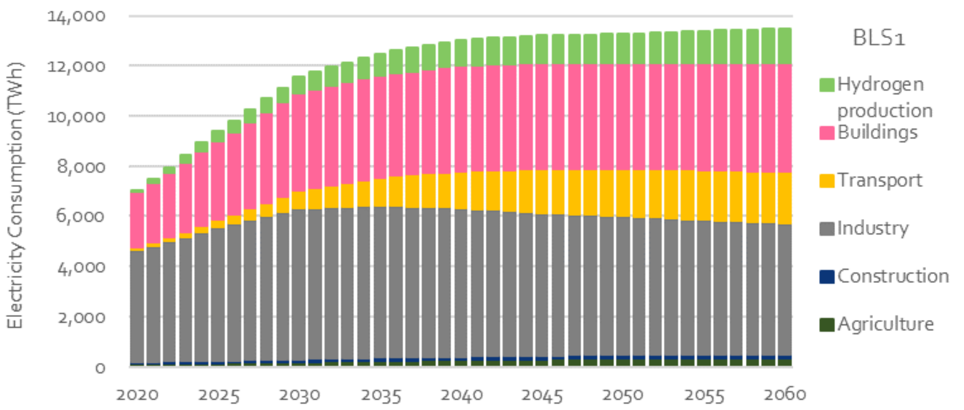
Scenario	2020	BLS1				CNS1				CNS2			
Year		2025	2035	2050	2060	2025	2035	2050	2060	2025	2035	2050	2060
Agriculture	123	162	243	345	345	174	290	459	459	174	290	459	459
Construction	77	91	121	152	152	91	123	171	171	91	123	171	171
Industry	4,453	5304	6069	5513	5240	5321	6499	6840	6201	5321	6499	6840	6201
Transport	99	320	1121	1887	2033	365	1303	1933	1984	365	1303	1933	1984
Buildings	2,227	3117	4064	4222	4352	3117	4142	4609	4732	3117	4142	4609	4732
Hydrogen production	71	403	866	1131	1347	583	2317	3092	2965	583	2317	3092	2965
Total	7,051	9398	12485	13249	13469	9651	14675	17103	16512	9651	14675	17103	16512

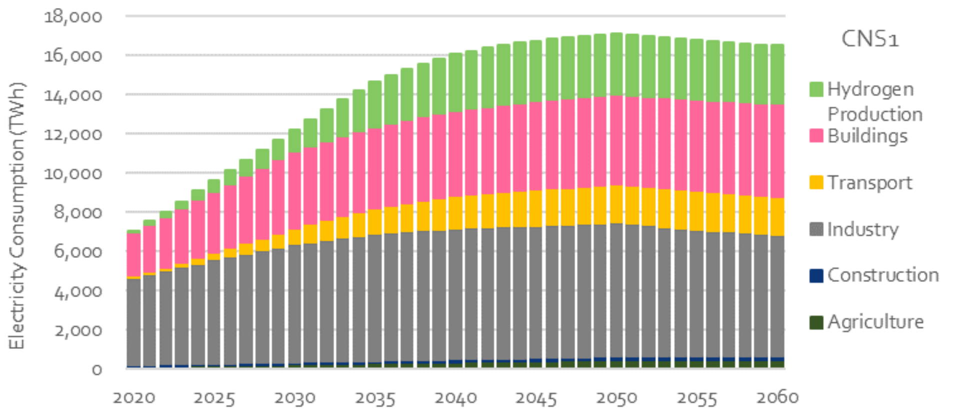
Structural changes in power consumption mix

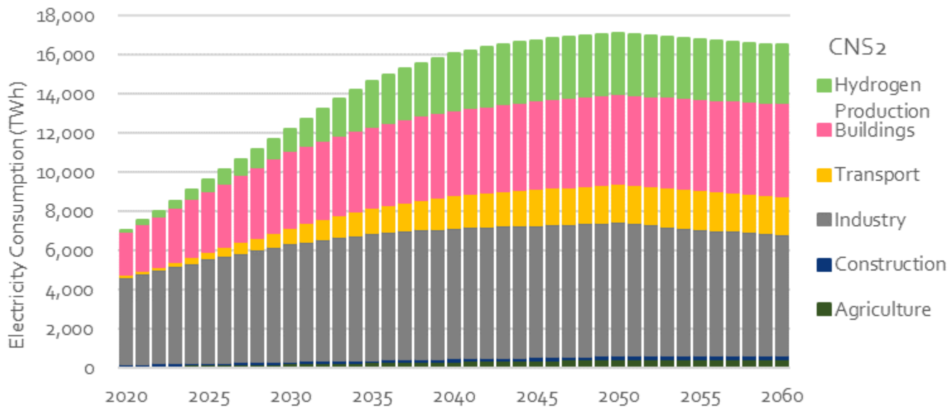
Currently, the **industrial sector** has the largest share in the overall power consumption. As China has reached the middle or late stage of industrialisation, there is a rapid transition from low-end manufacturing and heavy industry to urban industrials and high-value services. The power consumption in industries has very limited growth potential due to the improvement of electricity efficiency and the decline of industry share of the Chinese economy.

The significant power consumption growth happens in the **transport sector, hydrogen production and building sector**. To support the development of the Information industry, more data centres are expected to be placed in China to handle the massive amount of data. The need for data imposes more electricity demand in building sector. Similarly, due to the increasing numbers of electric vehicles (EV), the electricity demand in transport sector grows dramatically. Both scenarios assume increasing uptake of hydrogen, especially for industry. Hydrogen could be used as the reducing agent to replace coking coal for crude steel, and also to produce ammonia, replacing current coal-based synthetic ammonia production technologies. In addition, hydrogen has a potential in replacing oil products in transport sector. The hydrogen production in BLS1 consumes 866 TWh in 2060, 7% of total power consumption. Buildings consumes 4064 TWh in 2035, almost twice as much as 2020.

Figure 5-1: Electricity consumption in China by sector from 2020 to 2060 in BLS1 (top), CNS1 (middle) and CNS2 (bottom)



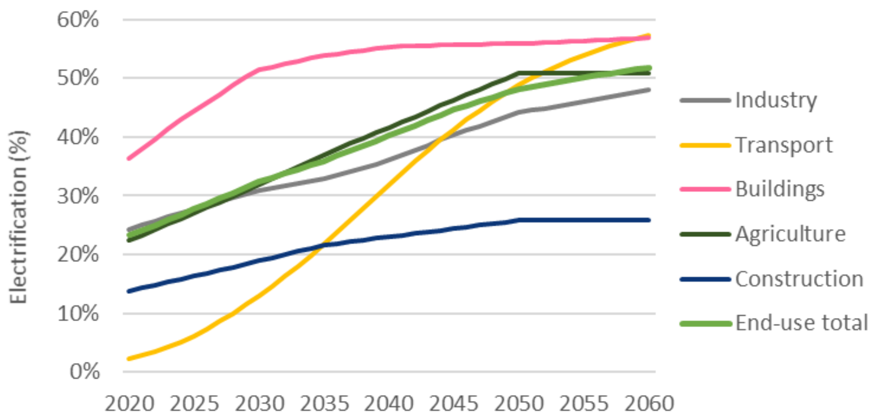




Electrification in each of the different end-use sectors

China sees a continuous electrification in all sectors, and the electrification rate of the total end use consumption more than double, from 23% in 2020, 36% in 2035 to 52% in 2060, in BLS1. In the period from 2020 to 2060, the building sector has the highest degree of electrification, and increases from 36% to 57 %. Industry and agriculture also have a high electrification degree: industry sector sees an increase of electrification rate from 24 % to 48 %, agriculture sector sees the increase from 22 % to 51 %. Transport sector has the fastest electrification, increasing about 16 times from only 2 % in 2020 to 57% in 2060, while construction sector increases electrification degree most slowly, only doubling from 14 % in 2020 to 26 % in 2060.

Figure 5-2: Electrification progress of various sectors in BLS1



Electricity generation and supply

To support the growth of electricity demand and to accelerate the energy transition, it is necessary that China's power supply significantly transforms and rapidly integrates more renewable energy to replace fossil fuel especially coal. In the 14th Five-Year Plan period, onshore wind power and photovoltaic takes the lead to be cost competitive with coal power. Renewable power is the major source to substitute incremental electricity consumption, and the investment in renewable capacity should be dominant in terms of new installations. After 2025, renewable power plays an even stronger role in power sector. As addressed in previous studies and confirmed in the research this year, wind and solar becomes the backbone of power system before 2035 in terms of both capacity share and generation share, and coal changes its role in power system operation dramatically.

Table 5-2: Scale of installed capacities and key indicators

Scenario	2020	BLS1				CNS1				CNS2			
Year		2025	2035	2050	2060	2025	2035	2050	2060	2025	2035	2050	2060
Total Capacity (GW)	**2127**	**2769**	**4225**	**6298**	**6661**	**2885**	**4682**	**7760**	**8277**	**2745**	**4507**	**8608**	**8210**
Coal	1080	1171	1065	413	174	1171	1065	290	96	1213	1225	622	160
Coal CCS	0	0	0	109	126	0	0	219	219	0	0	0	12
Natural gas & oil	100	121	203	175	82	181	269	261	79	122	255	461	390
Natural gas CCS	0	0	0	0	8	0	0	0	0	0	0	116	118
Nuclear	50	63	84	97	97	63	84	97	97	63	84	97	97
Total RE Capacity (GW)	**896**	**1414**	**2873**	**5502**	**6174**	**1470**	**3264**	**6893**	**7786**	**1346**	**2943**	**7311**	**7432**
Hydro	339	377	445	522	522	377	445	522	522	377	445	522	522
Wind	282	450	990	2200	2500	465	1025	2880	3300	505	965	3279	3817
Solar	253	550	1400	2716	3070	590	1750	3370	3845	433	1413	3339	2996
Biomass	23	37	37	38	21	38	43	42	18	31	119	114	24
Biomass CCS	0	0	0	22	53	0	0	24	46	0	0	50	65
Geothermal	0	0	0	2	5	0	1	5	5	0	1	5	5
Ocean	0	0	1	2	3	0	1	50	49	0	1	2	3
Fossil fuels(%)	**55%**	**47%**	**30%**	**11%**	**6%**	**47%**	**28%**	**10%**	**5%**	**49%**	**33%**	**14%**	**8%**
Non-fossil fuels(%)	**45%**	**53%**	**70%**	**89%**	**94%**	**53%**	**72%**	**90%**	**95%**	**51%**	**67%**	**86%**	**92%**
Renewable(%)	**42%**	**51%**	**68%**	**87%**	**93%**	**51%**	**70%**	**89%**	**94%**	**49%**	**65%**	**85%**	**91%**

14th Five-Year Plan period: a critical period to make a big step forward in the energy transition

The 14th FYP is an important window period for China to promote energy transformation and green development, as well as a critical stage for onshore wind power and solar PV power generation to fully reach grid parity without subsidies. China should give full play to the competitive cost advantage of renewable energy, adhere to market orientation, and give priority to renewable energy development and utilization. Regardless of many uncertainties during this period, it is firmly believed that clean transformation of the electricity production mix greatly increases the possibility of achieving a peak in carbon dioxide emissions and carbon neutrality. Therefore, it is projected that, although the installed coal-fired power capacity is likely to remain around 1200 GW, its share continues to decline, while the installed renewable power capacity and supply continues to grow during the 14th FYP period. Therefore, the 14th FYP period is a critical stage for China to take a big step forward in transforming its power mix.

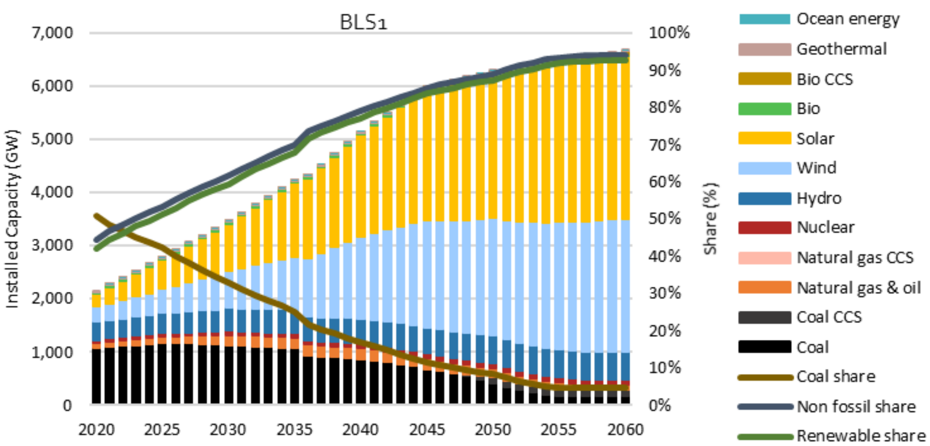
In BLS1, in 2025, China's total installed power capacity is projected to reach 2769 GW, of which coal accounts for 42%; and the total power *generation capacity* installed from *non-fossil fuel sources* is to reach 1477 GW, accounting for 53% of total installed power capacity. In CNS, driven by rapid increases in the shares of power generation capacity installed from non-fossil energy sources, including wind, PV, geothermal and biomass, the share of installed coal-fired power capacity is projected to decrease at a higher rate. By 2060, the share of installed coal-fired power capacity is projected to be only 96 GW in CNS1 and 160 GW in CNS2, taking up a 4% share of total installed power capacity.

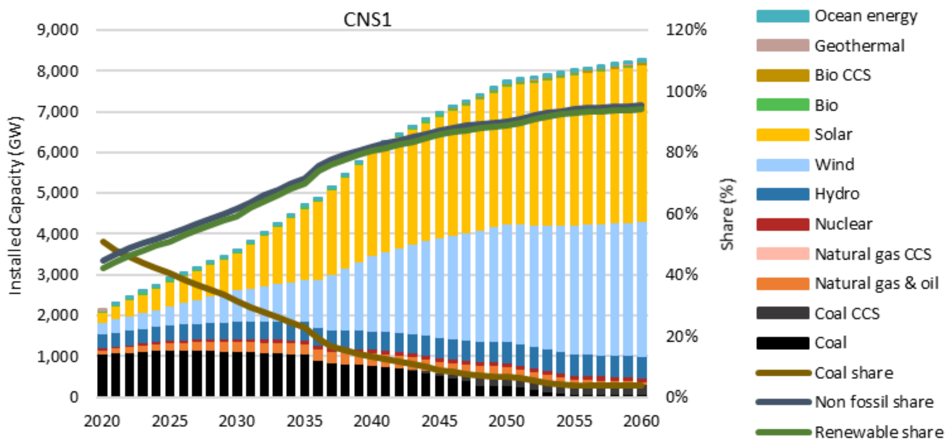
2025 to 2060: consolidation of the position of renewable energy, and achieving successful energy transition in power sector

By 2025, renewable energy sources account for 51% of the installed capacity and provides 34% of the annual generation mix. By 2060, the capacity installed of renewable sources goes up to 94% in CNS1 and 91% in CNS2, in turn providing 94~95% of the power generation. This clearly reflects the transformation of the Chinese power sector with renewable energy sources, predominantly wind and solar, making up most of the power supply mix.

On further analysing the electricity generation mix, it appears to be that wind plays a more dominant role than solar. While solar is expected to have lower costs, the final energy production is dependent on the resource availability and the system configuration. In the results presented, the power market is integrated giving an advantage to wind, which, unlike solar, is not produced all at the same time.

Figure 5-3: Installed capacity by technology 2020 to 2060 in BLS1 (top), CNS1 (middle) and CNS2 (bottom)





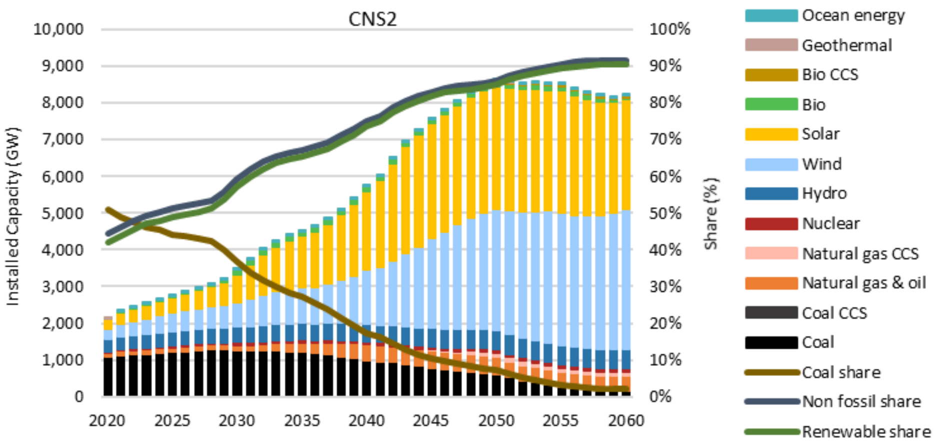
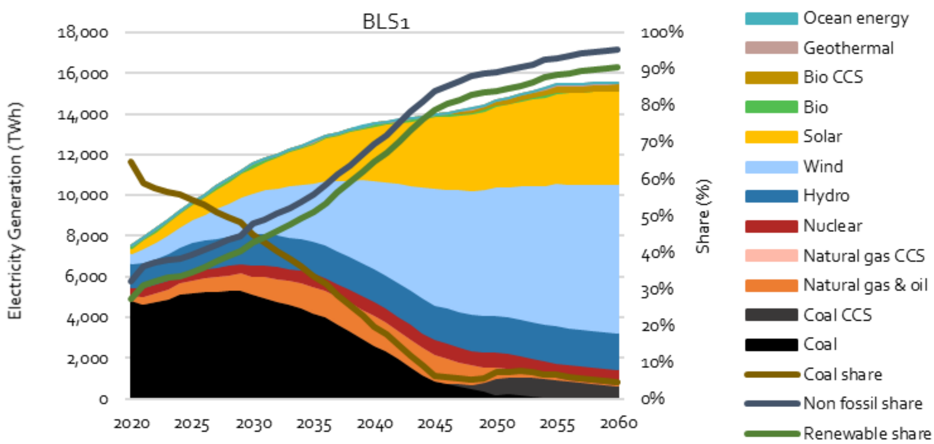
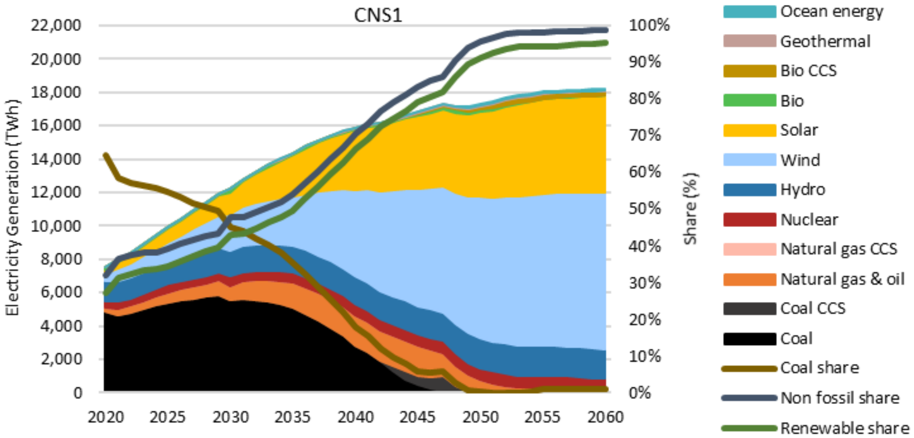
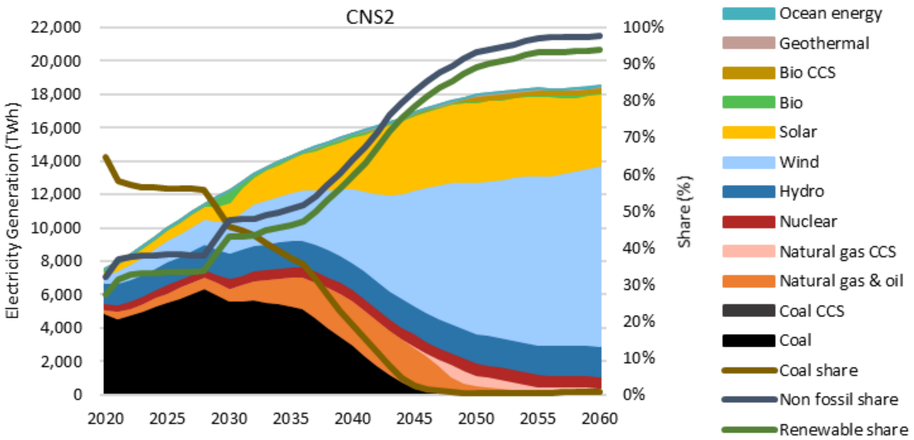


Figure 5-4: Generation by technology from 2020 to 2060 in BLS1 (top), CNS1 (middle) and CNS2 (bottom)







Power generation and capacity mix shifts towards renewable generators

Development of wind power

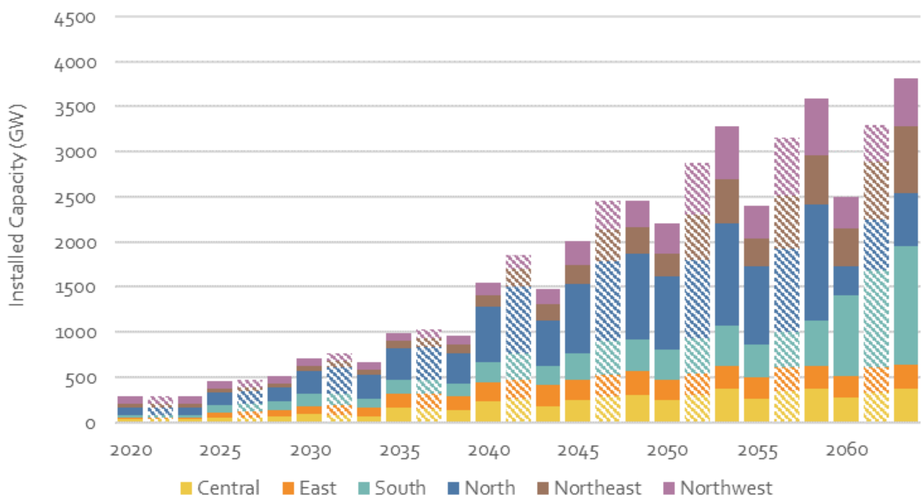
As one of the mature renewable power technologies, wind power is a leading renewable source in the energy transition in China. Onshore wind power in low-wind-speed areas and offshore wind power become gradually important after a rapid growth of centralised onshore wind power projects in Northwest and Northeast China. Electricity demand distribution and land resource availability become two important factors for wind resource utilisation. The development of wind power shows significant shifts in different periods on distribution and technology choices.

Supported by China's renewable energy policies, and driven by cost reduction, wind power industry maintains a steady growth during the 14th Five-Year Plan period, which leads to a cumulative capacity above 500 GW in 2025, of which offshore wind is more than 20 GW. In terms of regional distribution of new wind installations, the "Three Norths" region (northern, northeastern and northwestern parts) of China accounts for 60%, while the central east and southern regions account for about 40%.

Beyond 2025, wind power development continues to grow. In BLS1, installed wind power capacity reaches 990 GW in 2035, and further increases to 2500 GW by 2060, accounting for 37% of total installed power capacity. In BLS1, despite increases in installed wind power capacity shares in all regions, wind installations are mostly in the "Three Norths" region, particularly the northern region which sees the fastest growth. In CNS1, by 2060, installed wind power capacity reaches 3300 GW, including 1635 GW of onshore wind power, 1467 GW of distributed wind power, and 197 GW of offshore wind power. In CNS2, by 2060, installed wind power capacity reaches 3817 GW, including 2140 GW of onshore wind power, 2532 GW of decentralized wind power, and 145 GW of offshore wind power.

In terms of installed wind power capacity growth by region, by 2060, installed wind power capacity in the "Three Norths" region reaches 2286 GW in CNS1 and 2655 GW in CNS2, accounting for 69% of total installed capacity; that in remaining regions is 1014 GW in CNS1 and 1162 GW in CNS2, accounting for 31% of total installed capacity.

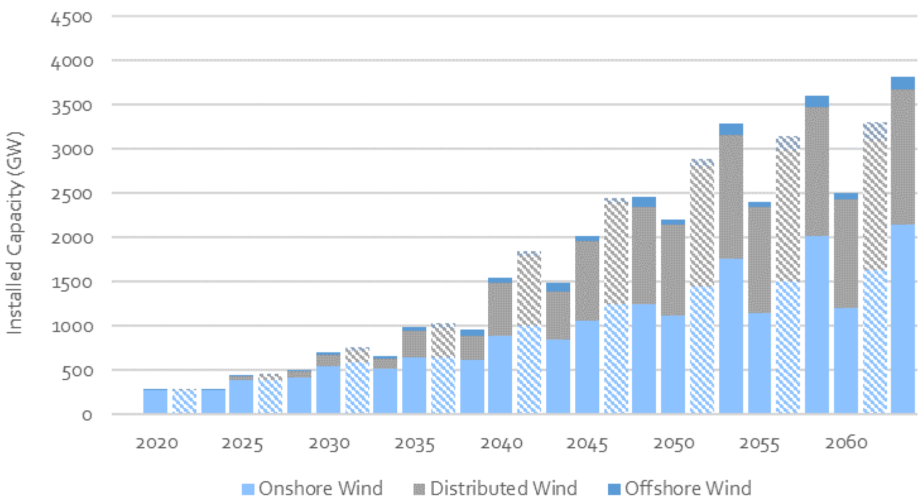
Figure 5-5: China installed wind capacity by region in BLS1 (left column) and CNS1 (middle column) and CNS2 (right column)



In the scenarios a rather ambitious opportunity for developing distributed wind is assumed. Distributed deployment allows for better utilising the land with multiple usage and matching the generation with local demand. Industrial parks and edges of farmlands are mostly considered for developing distributed wind. Statistics on farmlands[39], lists of industrial parks[40] and the geographical conditions[41] of different provinces are used to calibrate the resource potential in the scenarios. The overall distributed wind potential is approximately 1467 GW in CNS1, of which 44% of the potential is near load centres in South, East and Central China. Given similar wind power resources or efficiency, distributed wind has advantages on saving the transmission capacity and losses.

Offshore wind technology has become mature in recent years. The results also indicate the further development of offshore wind. As most of the coastal provinces are mostly populated and developed, the electricity demand is rich. Offshore wind shows the benefits on reducing system cost through avoiding long-distance electricity transmission. However, due to the limited potential in near shore and less attractive resources in near shore, the share of offshore wind maintains insignificant. The total installed Offshore wind capacity shows increasing trends in both scenarios. In BLS1, the installed Offshore wind capacity increases to 48.9 GW in 2035 and 72 GW in 2060. In CNS1, the installed Offshore wind capacity increases to 49.7 GW in 2035 and 198 GW in 2060. In CNS2, the installed Offshore wind capacity increases to 68.5 GW in 2035 and 145 GW in 2060.

Figure 5-6: China installed wind capacity by technology in BLS1 (left column) and CNS1 (middle column) and CNS2 (right column)



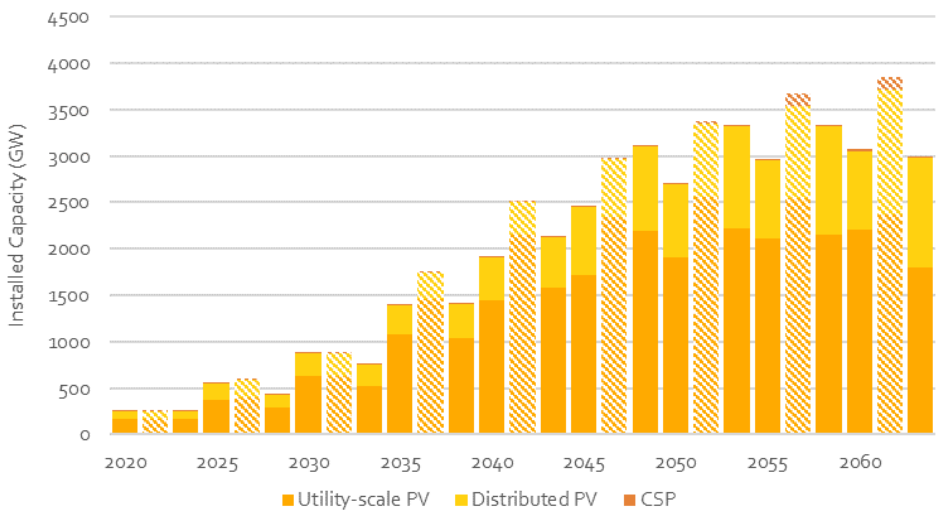
Development of solar power

Solar PV has experienced a rapid growth since 2012, driven by the advances of technology and rapid cost reduction. It has become one of the most competitive technologies that accelerates the energy transition in China and worldwide. Solar PV, especially distributed PV for self-use, has become cost competitive in a very short period. CSP has the potential on providing flexibility and inertia to the system. However, due to limited potential sites and high cost compared with solar PV, CSP does not have a large share in the capacity mix.

The total capacity of solar power in 2020 is 253 GW. By 2025, the total capacity reaches more than 500 GW, indicating a rapid development of solar power. By 2035, even though distributed PV keeps a high growth rate, utility-scale PV is still the majority and accounts for 73~80% of the total solar capacity.

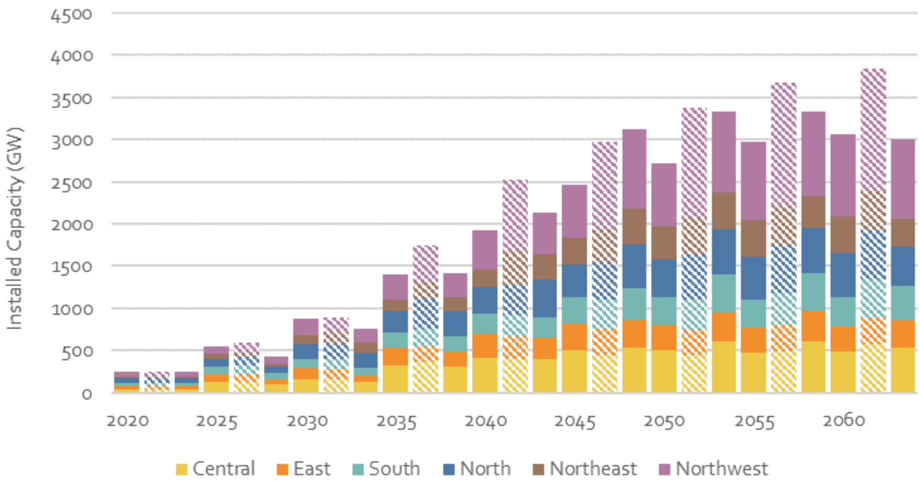
In BLS1, solar PV installations continue to grow, reaching 1400 GW in 2035 and 3000 GW in 2060. In CNS1, solar PV installations peak at 3340 GW in 2051. Beyond 2050, with some solar PV installations built in earlier years reaching their service life and being decommissioned on a large scale, PV installations gradually decrease to 2997 GW in 2060 in CNS1. Of all PV installations in the CNS2 in 2060, utility-scale PV is 1795 GW, accounting for 59.9% of total installed solar PV capacity, and distributed PV is 1180 GW, accounting for 39.4%. The remaining is CSP, which only takes up a very small share.

Figure 5-7: China installed solar PV capacity by technology in BLS1 (left column) and CNS1 (middle column) and CNS2 (right column)



In terms of the current status of regional distribution, China is and will continue to build utility-scale PV power plants in the northwest and northern regions which are abundant in solar energy and idle land resources (e.g. deserts); considering the hydropower development and grid connection conditions, the country is also planning to build solar power bases in such areas as Qinghai, Gansu and Xinjiang, and exploring new solar power generation and construction modes, i.e. hydro-PV complementation, and wind-PV complementation, while in the central and eastern regions placing equal emphasis on concentrated and distributed development. After the 14th FYP period, while all regions are expected to see substantial increases in installed PV power capacity, a majority of wind installations still remain in the northwest and northern regions. In terms of growth in installed solar PV capacity by region, in CNS1, by 2060, installed solar PV capacity in the northwest and northeast region reach 931 GW and 339 GW, respectively; that in the north region is 456 GW; and that in the central, eastern and southern regions is 541 GW, 324 GW and 403 GW, respectively, accounting for 18.5%, 10.8% and 13.5%, respectively, of total installed capacity in 2060.

Figure 5-8: China installed solar PV capacity by region in BLS1 (left column) and CNS1 (middle column) and CNS2 (right column)



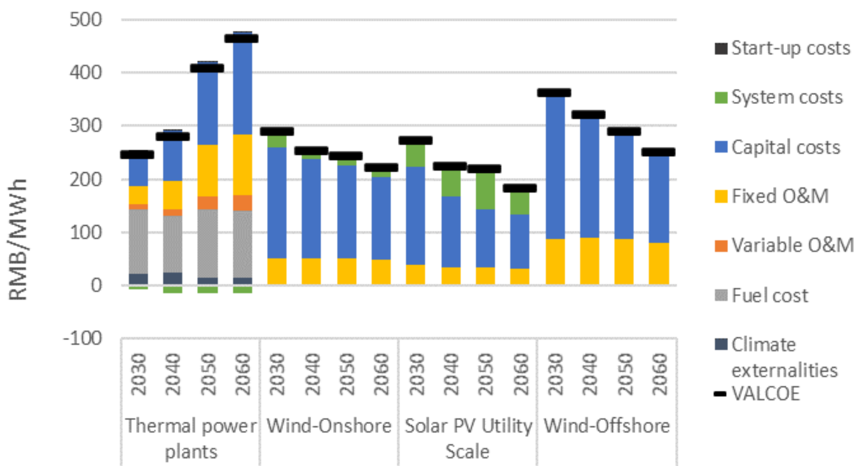
In addition, China is making great efforts to promote grid-connected distributed PV power system installed on the rooftops of buildings, provide incentives for the installation, where possible, of grid-connected PV power systems on rooftops of urban public facilities, commercial buildings, and industrial park buildings, etc., and give priority to the development of PV power generation in areas that demonstrate relatively good economic efficiency. However, due to constraints such as light conditions, land supply and ecological conservation, not all cities are suitable for distributed PV development on a large scale. In September 2021, NEA announced a first-batch list of pilot counties (cities and districts) submitted by provinces under the *Pilot program of county-wide rooftop distributed PV development*, including 676 counties planning for distributed rooftop PV development pilot projects.

Technology progress creates clear cost advantage for renewable generators

The development in generation costs is one of the main drivers for the share of investments in different power system technologies presented in the long-term CETO scenarios. In order to compare different technologies over time, they can be expressed by Value Adjusted Levelised Costs Of Energy (VALCOE). The VALCOE of a technology is a measure of the cost of energy based on the levelised costs of energy (LCOE) but adjusted to consider the added system cost provided by the specific technology. The system cost is in this case calculated as the difference between the electricity settlement price and the regional electricity price of a technology, which indicates how much higher/lower the unit earns in electricity revenue. Included as well is heat sales revenue on CHP units. The system cost will therefore vary between units and regions.

For fossil fuel technologies, the VALCOE is expected to rise due to higher capital costs and climate externalities (CO_2, SO_2 and NOx), and at the same time decrease in its full load hours (FLH) due to competitive renewable sources. Regarding renewable technologies, changes are owed to an expected decrease in capital costs, meanwhile adding competitive advantage in terms of pollution and climate. Focusing on the system cost, the fluctuating energy generation by renewables might incur further system cost compared to fossil fuel technologies. However, this is by far outweighed by their lower LCOE as illustrated in Figure 5-9: Cost division and VALCOE of main technologies based on the CNS2 for 2030-2060.

Figure 5-9: Cost division and VALCOE of main technologies based on the CNS2 for 2030-2060



It is to underline based on Figure 5-9: Cost division and VALCOE of main technologies based on the CNS2 for 2030-2060 that generation costs regarding solar and wind power are expected to decline over time, to the point where these technologies can achieve cost parity with fossil fuel technologies. Onshore Wind and Utility scale Solar PV reach parity during 2030-2040, while Offshore Wind gains parity around 2040. Consequently, coal power is expected to possesse very low full load hours in 2060, leading to an exceedingly high VALCOE.

In a long-term perspective, the VALCOE of solar and wind technologies are expected to be significantly below the VALCOE of fossil fuel technologies. Regarding coal power, the VALCOE is expected to increase due to higher capital costs and climate externalities (CO_2, SO_2 and NOx), but simultaneously to decrease in full load hours due to the competition with renewable sources. Regarding renewable technologies, changes are owed to an expected decrease in capital costs and comparative advantages in terms of reduction potentials in pollution levels and environmental impacts associated with renewable technologies. When inspecting system costs, the fluctuating energy generation by renewables might incur higher system costs compared to fossil fuel technologies. However, this is by far outweighed by their lower LCOE as illustrated in Figure 5-9: Cost division and VALCOE of main technologies based on the CNS2 for 2030-2060.

While the trends represent a national average for China, the VALCOE values depend on local conditions of technology installation since the prices are affected by the obtained full load hours, procuring-, and installation costs. As the EDO model considers local conditions regarding the provinces, different provinces possess different VALCOE for the same technology. However, despite possible differences in FLH over time, renewable energy sources are expected to be the most cost-effective technologies in at least 2040.

5.3 Flexibility and system integration

Overview of flexibility development

Power system flexibility refers to the ability of a system to cope with changes in the power supply and demand, to maintain a balance between supply and demand. Compared to the basic safety, requirements regarding the reliability and economic efficiency of the power system operation, flexibility has become an indispensable indicator to measure system performance characteristics considering sharply rising uncertainties with the current power system. China's flexibility resources are distributed on the power generation side, grid side and demand side. With the rapid development of technologies, energy storages have also become an advantageous technology to integrate and secure the flexibility of the power system, which cannot be ignored.

Generation-side flexibility resources include conventional hydropower and thermal power units, which are the most important utility-scale resources for frequency regulation, peak regulation, and reserve purposes. Conventional hydropower uses the potential energy stored in water reservoirs, such as rivers, to generate power. The technology can provide regulation services on a multi-year, annual, seasonal, weekly, or daily basis according to the reservoir capacity. Thermal power units, mostly coal-fired and gas-fired, provide regulation services by lowering the minimum output, increasing the ramp-up rate, reducing the start-up time or through electricity- and heat decoupling. All approaches share the common characteristic of rapid start-up/shut-down and fast load regulation. Since gas-fired power units outperform other types of units from the standpoint of occupied land area and environmental protection, their advantages as flexibility resources become increasingly prominent with the rapid development of distributed renewable energy.

Grid-side flexibility resources include grid interconnection, flexible alternating current transmission system (FACTS) and microgrid, which contribute to enhanced security and reliability of power supply. When region A and B achieve grid interconnection, region B can be considered as both a power source and a power load of A. By supplying power in both directions and using each other as standby sources, the power system of both Region A and B can withstand greater power and load fluctuations, reducing reserve capacity and installed capacity while enhancing the ability of the system to avoid accidents. The new technology FACTS has emerged in recent years and possesses the ability to improve the transmission capacity of the transmission lines and their voltage frequencies through controllability techniques, without being forced to change the grid structure. Based on distributed power generation, a microgrid can become a regulatable load of a larger grid by switching between islanded and grid-connected modes.

Demand side flexibility resources include incentive-based demand side management (DSM) and tariff-based demand side response (DSR), which help to smoothen load fluctuations and reduce peak-to-valley differences. Incentive-based DMS involves peak load shifting and promotion of energy-efficient appliances through administrative means, aimed to change electricity consumption patterns and to improve the end-use efficiency. On the other hand, tariff-based DSR stimulates consumers to change their electricity consumption patterns with the objective to reduce the electricity demand and consumption according to market price signals, e.g., implementing peak-valley electricity tariffs, seasonal tariffs, or selling curtailed electricity on the market to earn from it.

Energy storage flexibility resources include pumped storages and new energy storage technologies. The combination of new energy storage technologies and renewable energy can significantly improve the utilization efficiency of renewable energy. Pumped storages can offer frequency, phase, and voltage regulation by transforming excess electricity in low load periods into high-value electricity in peak load periods, why it is considered as an important flexible resource - especially as an emergency reserve in current power system. Out of all new energy storage technologies, electrochemical energy storages, mainly lithium-ion and lead storage batteries, contains a share around 85% in efficiency. This technology possesses a quick response time, but currently attributes with a small storage capacity and the economic efficiency needs to be improved. Due to the rapid speed of technological evolution, it is assumed that the integration of different energy storage technologies can fulfil the flexibility demands of the power system at different time scales.

Table 5-3: Performance comparison of different energy storage technologies in 2018

Energy Storage Type	Capacity (GWh)	Response Time	Efficiency (%)	Investment (RMB/kWh)	Lifetime (years)
Pumped storage	＞2	10s～40min	87	45～85	40
Electrochemical energy storage	＜0.2	＜1s	70～90	800～4800	20～30
Flywheel energy storage	＜0.5	＜1s	90～93	170～420	20～30
Compressed air energy storage	＜100	1~10min	80	12～85	30

Major policies in 2021

During the first year of the 14th Five-Year Plan (FYP), it was announced that series of the National Development and Reform Commission (NDRC) and the National Energy Administration (NEA) policies aimed to accelerate the development of flexibility resources, to strengthen the emergency peak regulation capacity of the power system, and to support the construction of a new power system, where new energy technologies play a central role.

Flexibility resources and product diversification. NEA released updated provisions concerning the participation of grid-connected entities in power dispatch and ancillary services. While grid-connected entities only consisted of thermal and hydropower plants in the old provision, the new provision covers a broader range of technologies, such as nuclear power, wind, solar PV, pumped storage, new-type energy storages and dispatchable loads (including independent consumer, aggregator, and Virtual Power Plant (VPP)). The grid-connected entities participate in ancillary services share the compensation costs according to the new provisions. This indicates that projects involving new-type energy storage technologies can be connected to the grid in standalone mode and take part in ancillary services. Small users can become flexible resources in forms of aggregators or VPPs, hence establishing further opportunities to ancillary service developments. Several new ancillary service varieties, such as rotational inertia, ramp-up and fast interruptible load, are also added in the updated provisions.[42]

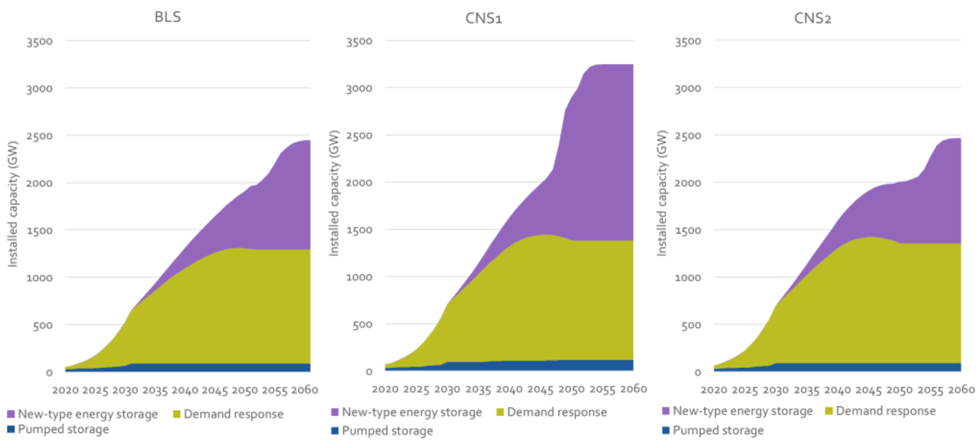
Implementing supportive measures for peak load regulation capacities, prior to grid connection of wind and PV power projects. From 2021 onwards, all market-based wind and PV power projects approved need to be equipped with or purchased at least by 4 hours/15% of the project's rated power of energy storage or peak regulation capacity, which shall be deemed as a prerequisite for grid connection. Those wind and PV power projects equipped with more than 20% will be prioritised in the grid connection. Projects that fall within the scope of an energy storage/peak regulation capacity are pumped storages, electrochemical energy storage stations, gas-fired units, solar thermal power plants, and coal power flexibility retrofitting. Provinces can make appropriate dynamic adjustments by considering their specific context. From 2022, NDRC will update the allocation ratio annually.[43]

Strengthening the role of pumped storages. According to NDRC's *Medium and Long-Term Development Plan for Pumped Storage (2021-2035)*, China aims to double the total installed capacity of pumped storages in operation to 62 GW by 2025, and further increase it to 120 GW by 2030. [44] Currently, the total capacity of China's pumped storage projects in operation is 32.5 GW, with Guangdong, Zhejiang and Anhui occupying the top three positions. The total capacity of pumped storage projects currently under construction is 54.0 GW, 60% of which are in North and East China. With that, China endeavours to further refine the pumped storage tariff mechanism and to clarify the value and allocation mechanism for ancillary services, it provides.[45]

Flexibility development outlook in different scenarios

In the BLS1, CNS1 and CNS2, coal power and pumped storages remain the most important flexibility resources in China for a considerable period, while electric vehicles and electrochemical energy storages play an increasingly important role. On the power supply side, the development of conventional hydropower continues to advance steadily in accordance with the national development plans. Meanwhile thermal power plants, primarily coal-fired power plants, accelerate the transition from baseload to regulated power sources. By 2035, coal-fired power plants are expected to complete the flexibility transformation, hence providing important support to fulfil the goal of building a "new power system mainly based on new energy". Section 5.5 *Outlook on Power Transmission and Grid Infrastructure* offers a systematic analysis of grid-side flexibility enhancement pathways. On the consumer side, during the period of 2020-2050, flexibility resources consisting mainly of smart EV charging and industrial demand response are projected to maintain relatively rapid growth before levelling in 2050. Regarding energy storages, conventional energy storage technologies, i.e., pumped storages, continue to play a significant role until 2030. After 2030, new-type energy storage technologies are assumed to be increasingly integrated, especially electrochemical storages and EV-V2G technologies, with the aim to facilitate the fulfilment of China's 2060 carbon neutrality target.

Figure 5-10: Installed capacity of flexible resources in China's power system by technology from 2020 to 2060 in the BLS1, CNS1 and CNS2



In long term, the demand response and new-type energy storage technologies have great potential for development. According to CNS1, the demand response capacity rises from 35 GW in 2020 to 930 GW in 2035, an increase of 12.8% compared to BLS1 containing an average annual growth rate of 24.6%. It further increases to 1264 GW in 2060, an increase of 5.1% compared to the BLS1 with an average annual growth rate of 1.2%. In the CNS1, the installed pumped storage capacity rises from 30 GW in 2020 to 92 GW in 2035, an increase of 14.2% compared to the BLS1, possessing an average annual growth rate of 7.7%. By 2060 in the CNS1 the capacity reaches 115 GW, an increase of 29.6% compared to the BLS1, while the annual growth rate drops to 0.9%. The installed capacity of new-type energy storages rises from 3 GW in 2020 to 115 GW in 2035, an increase of 16.8% compared to the BLS1, with an average annual growth rate of 27.5%. It further increases to 1869 GW in 2060, an increase of 61.4% compared to the BLS1 with an average annual growth rate of 11.8%.

The development of the demand response in CNS2 is likely to CNS1 since there is no further growth in installed pumped storage capacity after 2035, and the annual growth rate of new-type energy storage capacity is far lower than the CNS1. Overall, the requirement of flexible resources of CNS2 is much lower since the installed capacity of VRE such as wind and solar PV in CNS2, which is significantly lower than in CNS1.

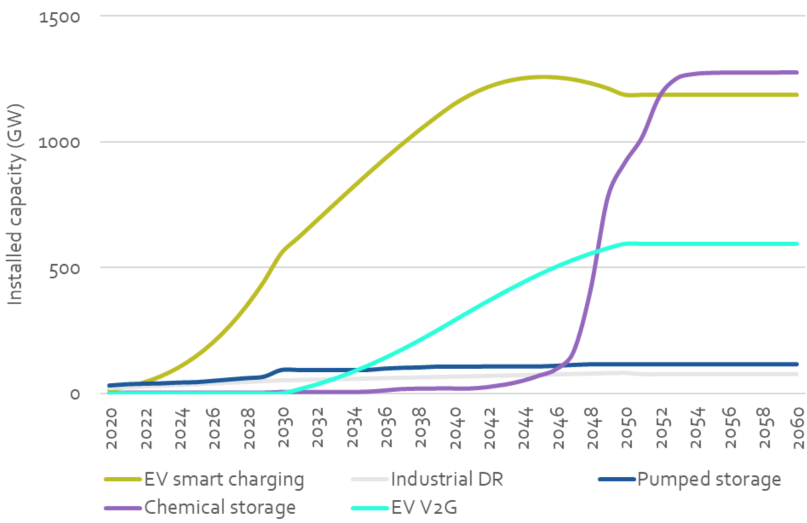
Table 5-4: Installed capacity of major demand response and energy storage technologies (GW)

Scenario		2020	BLS1			CNS1			CNS2		
Year			2025	2035	2060	2025	2035	2060	2025	2035	2060
Demand response (DR)	EV smart charging	14	140	765	1126	145	870	1187	145	870	1187
	Industrial DR	21	36	59	77	36	59	77	36	59	77
Pumped storage		30	44	89	89	44	92	115	43	91	91
New-type storage	Chemical storage	3	3	3	595	2	6	1275	2	4	520
	EV V2G	0	0	96	563	0	109	593	0	109	593
Total		**68**	**222**	**1011**	**2450**	**227**	**1137**	**3248**	**227**	**1133**	**2468**

In terms of regional distribution, North and Central China have abundant resources in demand response and energy storage technologies in all three scenarios. By 2060, the two regions combined are expected to share around 40%. The difference is that both BLS1 and CNS2 have abundant resources in East China, with a share of 18%~19%, while CNS1 deploys more flexible resources in Northwest, projecting a share of 22%. South and Northeast China possess both relatively few flexible resources, each with a share of less than 15% in the three scenarios. Nevertheless, regardless of the region and scenario, the development of EV smart charging, EV-V2G and electrochemical energy storage most significant in terms of specific technologies.

Considering the CNS1, EV smart charging develops on a large scale from 2020. Initiating by 2030, EV-V2G also enters a scale development stage while EV smart charging continues its high growth. By 2050, a relatively complete flexible service system for EVs is integrated. Thanks to continuously declines in related costs, the integration of electrochemical energy storages is expected to increase after 2040, and by 2060 to overtake the pumped storage capacity and industrial demand responses, being one of the most important flexibility resources in China by then.

Figure 5-11: Installed capacity of flexible resources by specific technology from 2020 to 2060 in the CNS1

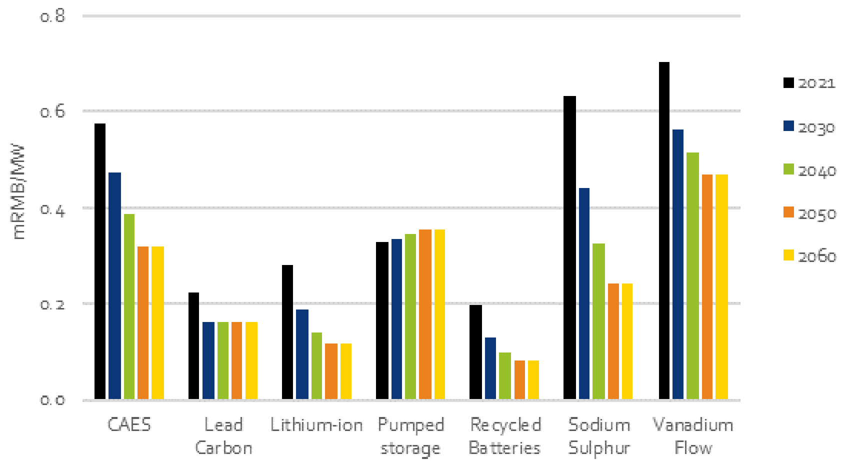


Costs regarding electricity storages decrease while increasing in value

Increasing amounts of fluctuating renewable electricity require an adequate storage capacity to increase the supply efficiency of renewables by offering flexibility services. Currently, pumped storages and electrochemical energy storages are the most important energy storage facilities in China, accounting for 89.3% and 9.2% respectively of the total energy storage capacity by 2020. Among various types of electrochemical energy storage technologies, lithium batteries have the largest cumulative size accounting for 88.8%, followed by lead battery (10.2%), flow cell (0.7%) and super-capacitor (0.1%). [46] Due to the assumption in CETO that hydro power, and thereby pumped storages, generally is further developed during certain decades, pumped storages are expected to be the dominant storage technology in the short to medium term. However, large reductions in costs regarding lithium-ion batteries indicates that the battery type is expected to overtake pumped hydro in installed capacity by the mid-2040s.

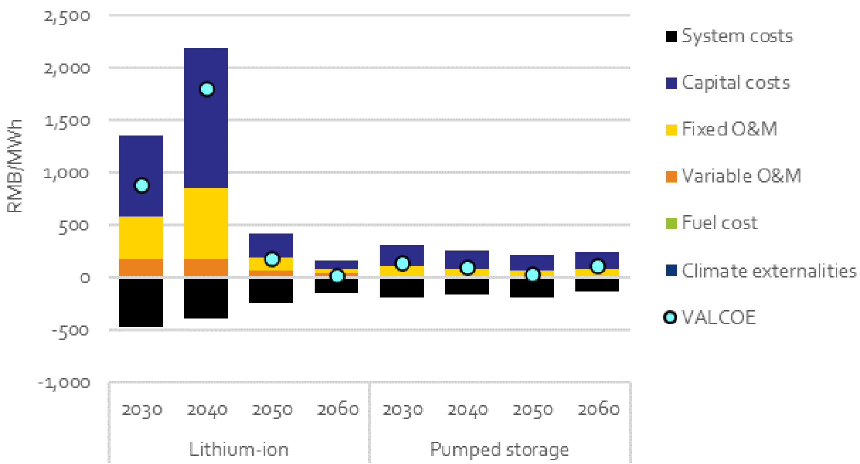
Capital expenditures related to all included storage technologies are expected to drop significantly until 2060. Nevertheless, lithium-ion batteries are in the medium to long-term expected to be the cheapest alternative, including cost of operation, thus it is the main future choice of large-scale storage technology. The development in capital expenditure of storage technologies indicates that lithium-ion batteries can compete with pumped storage by the mid-2020s. However, it is important to notice that due to existing policy targets of developing hydro power towards 2050, the deployment of hydro power in the model is not driven completely by its cost-effectiveness.

Figure 5-12: Capital expenditures per installed capacity of storage technologies from 2020 to 2060



Moreover, sudden shifts in the pace of installing lithium-ion batteries in 2050s are constrained in CETO, relatively to the installed capacity of previous years to emulate real-world scale-up, where capacity seldomly increase immediately from year-to-year. This affects the cost-effective approach and leads to lock-in of previously installed technologies. This is illustrated in the figure below, where the system benefit (i.e. negative system costs) for lithium-ion batteries in the long-run can almost outweigh the costs.

Figure 5-13: Value-adjusted LCOE for lithium-ion batteries and pumped storage from 2030-2060 in the CNS1



With that in mind, it is apparent that flexibility providers will possess a high system value in the long term. But the up scaling should be based on a cost-effective approach through market price signals, which can ensure that regional perspectives are accounted, so that the most feasible technologies are installed at the right time. Lithium-ion batteries may provide other services to the power system, such as frequency responses, entailing an earlier introduction. The key is that flexibility should not be seen as a goal, but a need approached by the market i.e., the power system. Market price signals are the best solution to ensure that the most cost-effective technologies to provide flexibility are activated. Particularly, the success of technologies depends on several aspects that differ between regions and over time. [47]

More complex dispatch operation and shifted balancing paradigm

With a large penetration of variable renewables, system operating paradigms shift towards covering the variability of renewable production by providing more flexibility. On both the power generation and consumption side, various flexible sources, including storages, V2Gs, load shifts, and EV charging are mobilized to accommodate the power system fluctuation caused by a high share of variable renewables. The share of mobilized power consumption will therefor increase.

Figure 5-14: Hourly power balance in China's power system in the winter 2035 in the CNS1

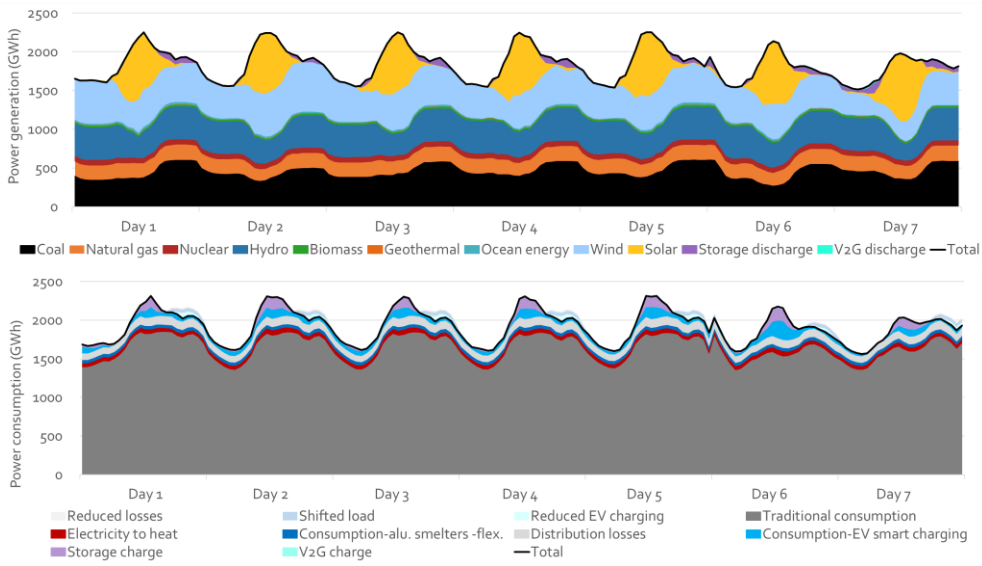


Figure 5-15: Hourly power balance in China's power system for 2035 summer in the CNS1

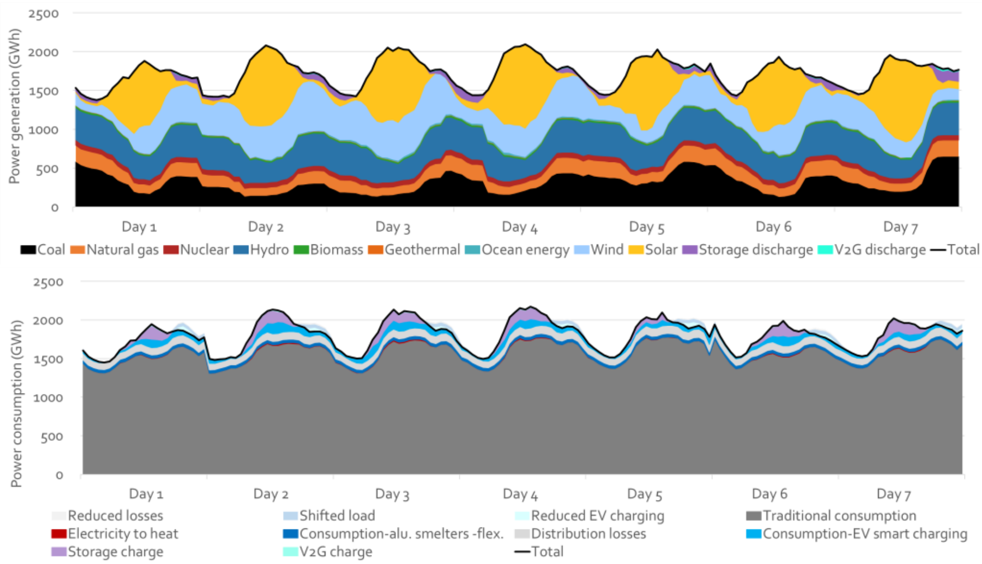


Figure 5-16: Hourly power balance in China's power system for 2060 winter in the CNS1

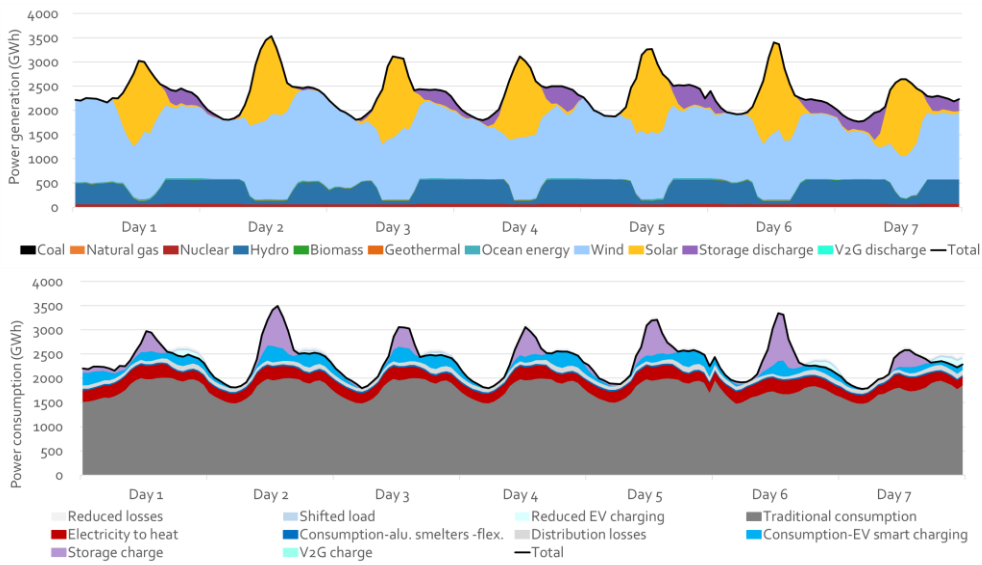
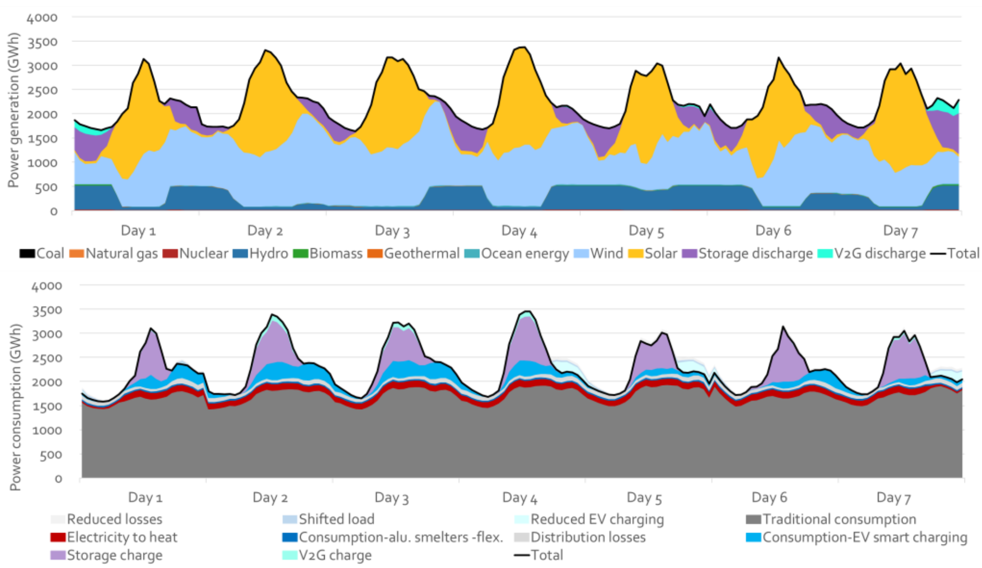


Figure 5-17: Hourly power balance in China's power system for 2060 summer in the CNS1



5.4 Power market reform

Evolution of China's power market reform

China's power market reform process has been developed since the beginning of the "reform and opening-up" campaign. This process can be divided into four major phases through identification of key events and the implementation of reform policies.

Figure 5-18: Timeline of China power market reform

The initial stage (from 1985) started during a period of rapidly increasing power demand, leading to sustained supply shortages with adverse impacts on the economic development. To alleviate the situation, the main emphasis during this phase was to attract and increase the investment in supply capacity. Through Directive 72, issued in 1985, the Government opened for power plant investments outside the central government, including governments on provincial and local levels, state-owned enterprises as well as private and foreign investors. Cost recovery was ensured through the "new price for new power units" scheme. Generators were offered power purchase agreements (PPAs) with predetermined utilization hours and plant specific cost-plus pricing. The "fair dispatch" principle was introduced in 1987 to ensure "transparency, equity and fairness" by guaranteeing equal opportunities for cost recovery to all investors. During this phase, the power generating capacity expanded and the provincial power systems were interconnected to form the six regional systems.

The second phase (1998-2002) was characterised by some of China's most substantial industrial reforms. The Government embarked on a process of diversifying enterprise ownership, increasing the autonomy and commercialisation of enterprise management, and promoting alignment of prices and market forces. The Government gradually withdrew from the operational management and the financing of power sector investments. A key event during the phase was the transfer of the majority of power sector assets from the Ministry of Electricity to the newly created State Power Corporation (SPC) in 1997. The Ministry was abolished in 1998 and its functions transferred to the State Economic and Trade Commission (SETC). These structural changes led to a certain degree of separation between government and regulatory functions from the power supply business. A new pricing policy, the "operating period tariff" was also launched in 1998. On-grid tariffs were set for an expected lifetime (rather than debt repayment period) and cost elements used in the tariff setting were benchmarked against similar plants. The first pilots for power generation divesture and generation competition were also launched in 1998.

The third phase (2002-2015) started with the publication of Document No. 5, "Power Sector Reform Scheme" which was motivated by apparent deficits in power system efficiency. The main goals were to improve efficiency through vertical unbundling and by introducing competition. The SPC was divided into two major grid companies, SGCC and CSG, 5 generation SOEs and four power service companies. To enable generation side competition, the plant-by-plant pricing structure was changed to a provincial benchmark price for coal-fired power plants. The State Electricity Regulatory Commission (SERC) was created as a regulatory body in 2003 and was in 2013 integrated into the National Energy Administration. SERC's goal was to establish six regional markets by 2006, including the necessary regulatory systems and institutions. In 2004/05, regional market pilots were planned to be launched in North-eastern, Eastern and Southern China, which were all abandoned due to growing supply shortages as the economy recovered from the Asian financial crisis. Besides the major price reforms losing traction, several related reforms were introduced like the Guidelines for Promoting Interregional Electricity Trading in 2005, Energy Conservation Dispatch pilots in 2007 and Generation Rights Trading in 2008.

The most recent phase (2015-2020) was kicked off with the release of Document No.9 "Opinions on Further Deepening the Reform of Power System" of 2015. A pricing reform, aimed to introduce market pricing mechanisms for the wholesale and retail segments, was the most important goal. Others were transmission reinforcements, improved regulation, and planning as well as the establishment of independent power exchanges. During this phase, provincial governments were assigned the task to implement the reform. Trading electricity across regions to improve the efficiency was also an important reform element. Although medium and long-term trading comprise the bulk of the market, 8 provincial spot market pilots have been implemented by power exchange companies, which facilitate power trading within the provinces. Interprovincial and interregional trading is managed by the Beijing' and Guangzhou' PXs within their respective footprints. On a provincial level, 32 power exchanges have been established.

Since the start of the power sector reform process, substantial progress has been made in several important areas. With the introduction of market price mechanisms and independent power exchanges, important milestones have been reached towards implementing a competitive power market. However, there still exist some barriers towards creating an accurately integrated national market. These barriers will be addressed in following section.

Updates on power market reform progress (2021)

Several Opinions on Further Deepening the Reform of the Electric Power System" (Zhongfa [2015] No. 9) (hereinafter referred to as the "No. 9 Document") jointly issued by the State Council and the Central Committee of the Communist Party of China (CCCPC) in May 2015, marked the launch of a new round of electricity system reform. In the light of China's carbon neutrality target proposed in October 2020, gradually integrating a higher share of new energy sources into the market has become an inevitable trend. While diversified social capital investments are needed, the traditional power trading model is difficult to adapt to the low carbon, distributed, digital and intelligent characteristics of the new power system. The key to efficient integration of high proportion of renewable energy, however, lies in a sound market mechanism. In that regard, the electricity market reform has never been more urgent. After vowing to become carbon neutral, China has accomplished several important advances in the electricity market reform.

The scope of the electricity market is constantly broadened

Regarding spot market pilot, in August 2017, the first batch of electricity spot market pilots were launched in eight regions, including Guangdong, Zhejiang, Shanxi, Gansu, Shandong, Fujian, Sichuan and Western Inner Mongolia. The pilots have completed the trial run of long-period settlement. The spot pilots are currently operating steadily. In May 2021, the second batch of pilots were launched in six provinces and cities, including Shanghai, Jiangsu, Anhui, Liaoning, Henan, and Hubei.

Regarding the auxiliary service market, with a high proportion of renewable energy being gradually integrated into the electricity grid, marginal costs of the electricity market are falling and system costs rising, which highlights the importance of market mechanisms to enhance the value and returns of system flexibility regulation resources. In November 2020, the nation's first-ever unified regional frequency modulation auxiliary service market system was officially operating in regions covered by China Southern Power Grid.

In addition to the onset of the second regulatory cycle of the power transmission and distribution tariff reform, China has currently put in place a basic regulatory framework for power transmission and distribution tariffs that focus on "permitted cost + reasonable revenue", which has changed the profit model of grid enterprises. During the period of 2018-2020, three consecutive reductions in commercial and industrial electricity prices were experienced. Since 2020, several documents, including *Pricing Methods for Power Transmission of Regional Grids*, and *Pricing Methods for Power Transmission and Distribution of Provincial-level Grids*, and policies governing power transmission, distribution, and sales prices in various provinces have been released. In 2020, the cost of electricity within the SGCC's business areas decreased by 55 billion yuan, with an average reduction of 3.037 cents/kWh in electricity prices.

Participants in electricity market trading are constantly diversified.

In recent years, there has been a significant increase in the number of diversified market participants on the power generation-, power selling- and consumer side. In 2020 more than 4,600 power selling companies were registered nationwide. A part of them explores the value-added businesses, such as integrated energy services. Same year, market-based electricity traded in electric power trading centres nationwide reached 316.63 billion kWh, peaking at 11.7% [48] annually. For the first time in history, the share of market-based electricity traded in SGCC business regions exceeded 50.6% of the total electricity sales.

The incremental power distribution pilot reform is an important starting point for the electricity reform. From 2016 until now, NDRC and NEA have approved five batches, totally 483, of incremental power distribution business reform pilots, covering 31 provinces and regions of which 79 were approved in August 2020.

New breakthroughs are made in the exploration of market-based renewable energy trading.

As far as the medium and long-term market is concerned, a pilot project on green power trading was officially launched. In a formal response letter ("*Green Power Trading Pilot Work Plan*") from September 2021, NDRC and DEA approved SGCC and China's Southern Power Grid to carry out a green power trading pilot, aimed to roll out independent green power trading varieties under the existing medium and long-term trading framework, guiding consumers in need of green power to conduct transactions directly with power generation enterprises and hence unleashing demand for green power. On September the 7th 2021, the first-ever green power trading was performed by the electric power trading centres in Beijing and Guangzhou. 259 market entities from 17 provinces completed 7.935 billion kWh of green power transactions either online or offline. Initial estimate suggests that these transactions may contribute to a reduction of standard coal by 2.436 million tons or of CO_2 emissions by 607.18 million tons[49].

Concerning the spot market, the electricity spot market is deemed as an effective mechanism reflecting the ultra-low marginal cost advantage of renewable electricity generation. Integrating renewable energy into the spot market lowers the cost of electricity and adds priority to new energy consumption patterns. According to *Notice on*

Further Improving the Pilot Work on Electricity Spot Market Construction jointly issued by NDRC and NEA in May 2021, it was proposed that efforts should be compiled to guide new energy projects to have 10% of their expected current electricity bid to feed into the grid through market-based trading or competitive bidding methods. Whereas the market-based trading part may be excluded from guaranteed purchase hours of the whole life cycle, thus confirming at a state level that renewable energy plays a role in spot market trading. In addition, surplus renewable power spot trading has been constantly carried out cross-regionally or inter-provincially in various localities. At of the end of 2020, more than 1,700 renewable power generation enterprises at the delivery end of SGCC's business regions, located in 14 provinces, participated in spot trading with 3.654 billion kWh of electricity, traded throughout the year, representing a 1.1 percentage-point increase in new energy utilization.

The first pilot project of market- based distributed PV trading pilots gets grid-connected.

In 2017, China started the market-based trading pilot programme on distributed power generation. Since then, NDRC and NEA have compiled several documents aiming to promote the market-based trading pilot on distributed power generation, while clarifying criteria for the network tariff in market-based trading. In 2019, NEA announced a list of pilots, covering 26 projects in 10 provinces and regions. In December 2020, the first market-based trading pilot on distributed PV power generation was grid-connected in Jiangsu province, marking a breakthrough. China currently adopted a model that allows distributed PV system owners to generate electricity for their own use and to deliver excess electricity to the grid. Currently, except the seven pilots of Jiangsu province, which are allowed to participate in market-based trading of distributed generation, and Zhejiang province allows distributed PV power generation to participate in green power trading, the other provinces have not yet commenced the market-based trading model. The pilot implementation progress so far indicates that to achieve large-scale promotion of market-based trading of distributed power, China still faces challenges, including grid connection, network tariff standards, land policies etc.

Liberalize on-grid tariffs for coal-fired power generation in an orderly manner.

According to *Notice on Further Deepening the Market-Oriented Reform of On-Grid Tariffs for Coal-fired Power Generation* issued by NDRC from October 2021, on-grid tariffs for coal-fired power generation are to be fully liberalized in an orderly manner. Fluctuation limits regarding the coal-fired power trading price are eased, in principle to 20%, from a previous 10% increase and 15 % decrease. With approximately 70% of all electricity generated by coal-fired power plants in China currently connected to the electricity market, following this policy release, the remaining 30% of coal-fired power generation will go into the electricity market as well. Thereafter, China's coal-fired power generation will in principle go into the electricity market in a bid to create a market-based electricity pricing mechanism. This could provide further impetus to other types of power generation to be delivered into the market, thus laying a solid foundation for full liberalization of the power generation side on-grid tariffs. As the market transaction price of energy-intensive enterprises is not subject to the 20% rise, the measure will subject energy-intensive enterprises to higher price fluctuations in market transactions. It will also form a cost transmission mechanism, providing guidance on energy consumption transformation through price signals, spur energy-intensive enterprises to increase input in technological renovation, improve energy efficiency, and promote the transformation and upgrading of the industrial structure.

Benefits, barriers, and reform needs of power market reform

Shortly, an efficient and well-functioning power market allows cost-effective optimisation of the dispatch by optimising the generation according to costs in the short run and by providing adequate signals on which long term investments in new power technologies are determined. To have an efficient and well-functioning power market, it is imperative for market design to identify and remove inefficiencies that are simply economic or regulatory in nature. In many cases, market reforms possess the potential to achieve cost-effective variable generation integration.

In fact, most market characteristics that support the integration of variable generation of electricity also promote efficient operation of thermal dispatchable units. Moreover, higher levels of variable generations increase the value of these characteristics, as the market incentives dispatchable units to follow the characteristics of variable renewable generations through its price signals. These effects result in lower costs in system operation from a governmental point of view and to the lowest electricity price possible for retail consumers.

In short term, the prices in the power market encourages producers to either ramp up or ramp down the generation and likewise for the consumers of electricity. Thereby both suppliers and consumers act accordingly to the needs of the power system since the price follows the balance of power supply and demand. In reality, power producers bid their short-term marginal costs of production, so that the market, based on a least-cost principle, can determine the price of electricity and thereby denounce the producers in the particular period. This encourages the power producers to participate actively on the market, adjusting their production on a day-to-day basis to benefit from the market participation on one hand and to avoid negative economic consequences, on the other hand.

In a concrete case, the market dispatch operation drove flexibility measures forward in Europe overall, by permitting the need of the market to be reflected through economic incentives. As a result, the power plants were prompted to operate more flexibly or to change their characteristics. While flexibility measures may be promoted through other incentives than market operations, permitting the market show its need through price signals and letting the suppliers determine the need, indicates that the least expensive measures will be deployed at first. However, this will only be the case for a well-functioning market where regulation, incentives, and market structures have been well-designed to reflect the needs of the system optimally. Furthermore, market players should operate under an economically rational behaviour, meaning according to the price signal observed on the market.

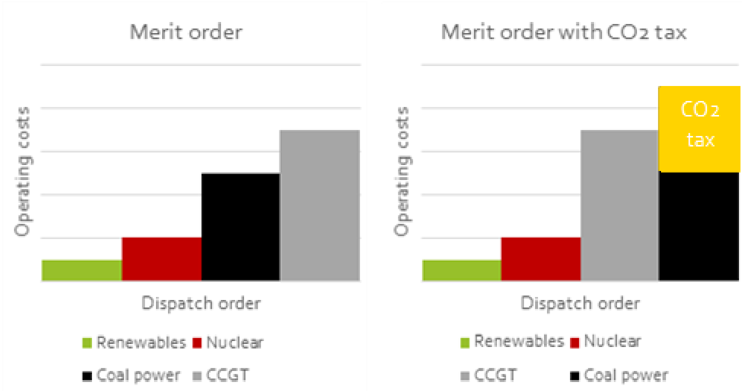
The market dispatch generates investments on the power market in Europe as well, as an additional benefit of the market condition. Power producers searching to invest in new production technologies can judge their costs related to an investment against the anticipated revenue from the power market by observing the historical power price. As an example, periods with high power prices indicate to the producers that there is a gap in the power market, which can be filled by cheaper sources of power generating technologies, illustrating how the power market can pave the way for least-cost investments. Again, it must be emphasised that a prerequisite is a well-functioning market where regulation, incentives, and market structures have been designed to reflect the needs of the system optimally. However, such benefits may not be accessible under existing market rules but can be harnessed if market designs are suitably adjusted. Hence, it is up to the policy makers or regulators to design the power market to deliver adequate price signals, which is why a power market should be viewed on as a great basis to frame the desired power system as opposed to a loss of control for policy makers.

CO_2 price as a policy maker's tool to decarbonise the power sector with a market

One tool that can assist policy makers in framing a power market and decarbonising a power system is a CO_2 tax. The price formation on a power market is influenced by many factors, such as fuel prices, distribution costs and taxes. In this regard, a CO_2 emission tax can be a beneficial tool to support decarbonisation purposes in the power system.

A CO_2 tax is a part of the overall costs of the producer, which also consist of various fixed and variable operational and maintenance costs. Adding these gives the short-run marginal costs of generating power, which is the basis of the merit order dispatch well-known from many spot markets. As the CO_2 tax is a part of the short-run marginal costs of a plant, the CO_2 tax is a tool for policy makers and regulators to regulate the merit order based on CO_2 emissions. The figure below illustrates how the CO_2 price affects the short-run marginal costs of power production.

Figure 5-19: Illustration of the effect of a CO_2 tax on the merit order curve on a power market



Additionally, a CO_2 price influences the long-term costs and in turn reduces the number of full load hours. As such, this affects the levelised costs of energy (LCOE) as it is a measure of capital and variable expenditures and full-load hours. Hence, the trends in LCOE are not exclusively driven by changes in variable cost, including fuel prices, but also allocated full-load hours.

The impact of a CO_2 tax is directly seen on the merit order dispatch and the CO_2 emissions. As mentioned in the introduction, CO_2 prices can be seen as a policy tool that can be determined to achieve certain emission targets, while in coordination with the power market, obtaining a least-cost pathway. As such, a CO_2 price is proved to be an effective way of encouraging the decarbonisation of the power system.

However, when designing a market, it cannot be emphasised adequately that a power system is a highly complex system constrained by multiple factors such as subsidies, power purchase agreements, and politically determined minimum full load hours. Hence, it is necessary to keep this in mind and to consider the various schemes, when adjusting a CO_2 tax and, even more importantly, designing a power market.

Forther reform needs

Despite the great progress that has been made in recent years, there are several areas that deserve attention from policy makers to create a competitive and integrated power market. A big obstacle towards achieving a national power market is the diversity of market designs currently implemented by provincial spot market pilots. While these pilots acknowledge the importance of short-term resource optimization on provincial level, major efficiency gains are currently prevented by the lack of regional and provincial market co-ordination. An initiative to harmonize some features of provincial spot markets could be assumed in this case. A strengthening of the regulatory authority might be necessary since governance and regulatory functions in China appear quite fragmented with responsibilities shared among different stakeholders. International experiences show that an independent regulatory authority is of high importance in driving reform processes.

- Power plants which are dispatched out-of-market distort price signals from organized markets.
- Fragmentation of liquidity through establishment of separated marketplaces (e.g. Green Power Trading) can be problematic. All generation technologies should bid into the same market. Let market forces in short-term markets decide through merit order, which units should produce and which not.
- Further unbundling of grid companies to focus on core activities (ref. recent announcement to de-merge manufacturing business of SGCC).

High-level market design for integration of Chinese markets and for integration of high penetration RE

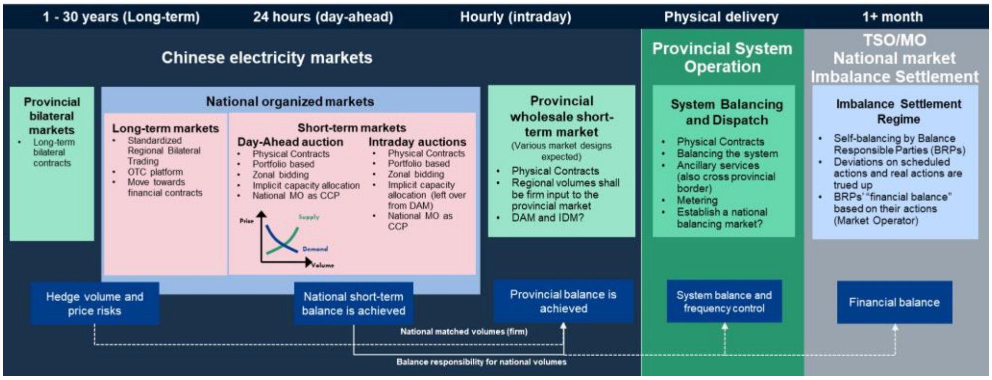
The following sections are based on the *Chinese Power Market Target Model* report and *Chinese National Power Market General Rules* report, prepared by Nord Pool Consulting AS in association with Energinet and Ea Energy Analyses as part of the "Power Market Reform Technical Cooperation with China" program between the National Energy Administration of China (NEA) and Norwegian Agency for Development Cooperation (Norad).

The Chinese power market is suggested implemented using a combined top-down approach in close cooperation with provinces, who should retain the responsibility for local dispatch and power balance. This follows naturally from China's multilevel dispatch organization and implies that the short-term (day-ahead) national market should clear prior to local markets, and that the matched national volumes should be used as input parameters to provincial short-term optimizations. Market participant schedules would thus be based on a combination of bilateral (long-term) contracts, administrative dispatch instructions, and contracts derived from national and/or provincial short-term markets. Provincial and regional dispatch centres therefore need to plan their dispatch based on input from multiple stakeholders and market segments.

To address this multi-level system optimization problem, the proposed target model consists of markets that cover different time horizons and serve different purposes. Long-term markets are mainly used for risk management and provide tools for market participants, who want to hedge their price and/or volume risks. A National Day-Ahead (auction) Market (NDAM) is proposed as the main market mechanism for short-term resource allocation and the optimized utilization of the transmission infrastructure. Prices derived in the NDAM are important prerequisites for well-functioning long-term markets. Intraday auctions can be used as a supplementary tool to adjust market schedules based on updated information close to physical delivery.

The suggested overall Chinese power market target model is presented in Figure 5-20.

Figure 5-20: Chinese target model and the timeline of trading. Source: Nord Pool Consulting



National Day-Ahead Market (NDAM)

Short-term optimization in the NDAM takes place the day before physical power delivery. This requires harmonized timings and information flows between the different players. A National Power Exchange should facilitate efficient market organization and take on the coordination role between local power exchanges, dispatch centres and grid companies. Provinces continue to operate local markets and dispatch centres will coordinate dispatch based on a combination of local and national rules.

The NDAM is proposed to be organized via an auction mechanism using a zonal bidding structure. Scarce interconnector capacities between bidding zones would be optimized through implicit market coupling based on allocated transmission capacity. Market coupling is considered the most appropriate practice for achieving economic efficiency. Access to transmission capacity is a key success factor for establishing an effective NDAM as it enables resource sharing across regions and provinces. Capacity allocation requires close cooperation between grid companies as calculation methodologies must be based on agreed and harmonized rules.

The main outcome of the NDAM are scheduled interconnector flows between bidding zones.

Market participant types in the NDAM will differ depending on provincial market design. Generic types of National Market Participants would be:

- Provincial Market Operator (PMO), or
- Provincial Market Operator with Central Dispatch (PMCD), or
- Special Generator, or
- Direct Participation of provincial market participants in the NDAM

National Market Participants bid their available capacity into the NDAM based on local power system balance. After clearing of the NDAM, regional and provincial market operators run local optimizations according to their own market designs, taking into account firm interconnector flow results from the NDAM.

A zonal market design provides bid submission via *bidding zones* which represent a geographical area, ideally with few structural grid constraints. In existing implementations, zonal boundaries are often drawn along administrative, e.g. country borders. Provinces may also implement several bidding zones, depending on local grid constraints. National Market Participants submit aggregated bids to the NDAM based on all the assets/unit information in their control area.

Roadmap for stepwise market implementation

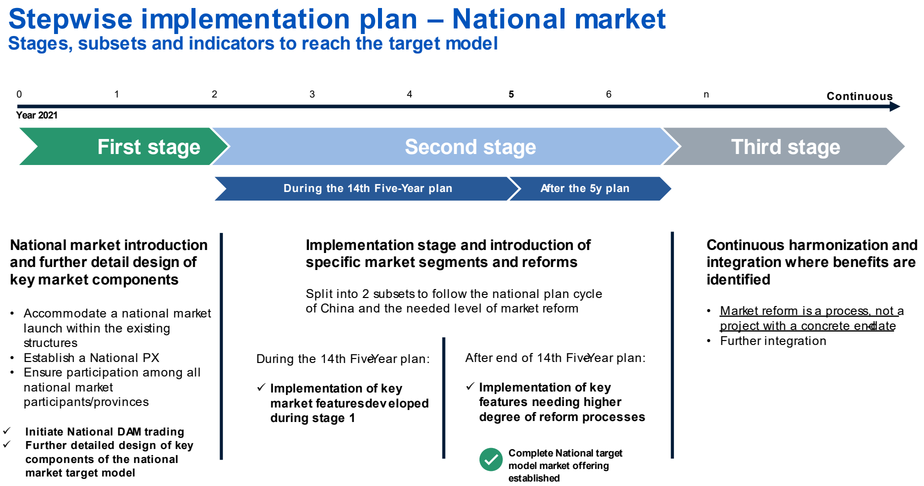
This stepwise implementation plan is suggested to be accomplished in three main phases.

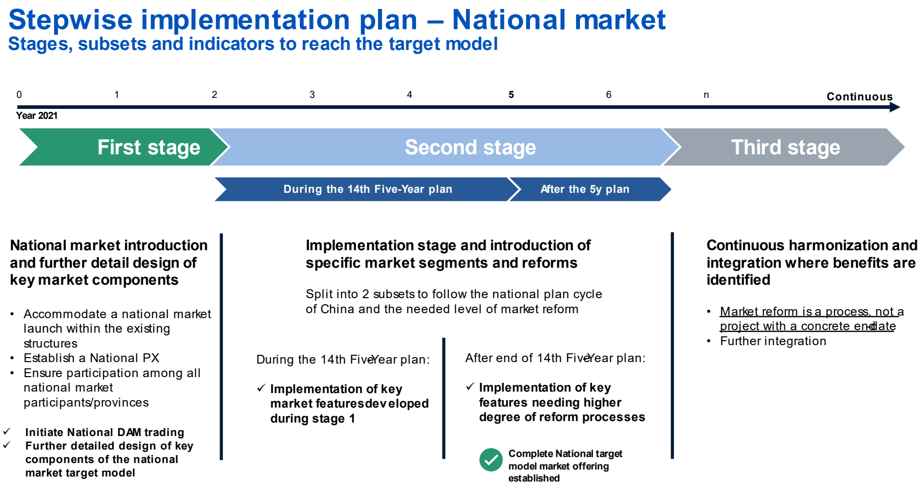
The first stage of the implementation should embed the NDAM within the existing Chinese power market structure. The initial market launch should be sped up, paving the way for knowledge acquisition of the Chinese resources and the implementation of further design steps later on. Key market design and market rules elements have been described in the *Chinese National Power Market General Rules* report.

During the second stage the focus should be on increasing the efficiency of the market. It is proposed to further harmonize capacity calculation methodologies with the aim to maximize the available capacities for the market and to introduce a national intraday auction market segment. Both will be important enablers for increased participation of VRE resources. An interprovincial balancing market should also be considered. New long-term bilateral contracts should be established as purely financial contracts, while existing physical contracts could be converted to financials. This is already practiced in some provinces for *direct trading* contracts during market trial operations.

The third stage is more generic. Power market reforms are continuous processes, as can be seen from international experience. It can be expected that further harmonization and integration efforts will be taking place in areas that are deemed beneficial for market efficiency by the Chinese authorities. The intention should be that, over time, the different provincial markets will converge towards the national market model and become closely integrated to provide an efficient and interconnected Chinese power market.

Figure 5-21: Stepwise implementation plan





Policy recommendations

China's power market reform is ongoing and being deployed primarily through piloting in the provinces with an effort learn from these pilots and expand laterally to other provinces. We recommend that this guided bottom-up approach, be supported by the development of a national market framework, to ensure efficiency of inter-provincial and interregional trading. Allot of the potential efficiency gains that can arise from power market reform, involves coordinated market-based scheduling of the country's diverse regions' different resource endowments, i.e. connecting, wind, solar, hydro and thermal generation to demands, dynamically across the country according to the immediate situation. Thus a national market spot market should be setup to ensure market interconnection of the provincial spot markets, to promote overall efficiency. A design for such a market setup was presented in the previous section.

Transition from VRE surplus market[50] to National Day-Ahead Market

The VRE surplus market was established in 2017 to promote VRE integration through reducing curtailment. This market contains many valuable elements which make it a good potential candidate for a truly national day-ahead market. However, some changes would need to be implemented both, on national and provincial levels, before this can be implemented. Examples are permitting bi-directional power flows on interconnectors, implementing implicit auctions as well as permitting additional generation technologies for participation.

Spot market harmonization

A major obstacle towards tighter integration of provincial and regional power markets is the variety of different provincial spot market designs that have been implemented following Document No.9. Therefore, it is recommended to engage in harmonization efforts which will allow for a more optimal utilization of existing resources.

Increased focus on intraday market for shorter term schedule adjustments

Existing short-term markets in other jurisdictions (e.g. intraday markets in Europe) already possess the necessary features (high time granularity, short lead-time, cross-border capacities) to provide market participants with the opportunity to bid in their flexibility in the market. Although short-term adjustments are possible via real-time markets in some spot pilot provinces, an intraday market for a wider geographical area currently only exists as part of the VRE surplus market whose use should be expanded.

Strengthen independence of power exchanges

One of the major goals of the power market reform should be the transfer of resource allocation authority from the government level to market entities. Driven by market supply and demand, market prices should be formed to the extent possible without governmental intervention. In order to ensure the trust of market participants, power exchanges should take on a stronger role in market operations and become (at least partly) independent of grid companies. This will safeguard fairness and impartiality of transactions.

Increased co-operation between grid companies

In order to allocate as much as possible interprovincial and interregional transfer capacities to the market, joint methods need to be established between the different grid companies. This will enable improved national resource allocation. Increased co-operation may also result in other benefits such as the sharing of balancing resources.

- Distributed generation can already today participate in the market on equal terms with other generation sources. Grid constraints should be taken into account during the grid connection approval process.
- Transactions of more than 15 minutes (intraday, day-ahead, and medium- to long-term transactions) should be responsibility of power exchanges.

5.5 Power transmission and grid infrastructure planning

Interprovincial grid capacity and power flow

Each provincial grid is part of one six larger grid regions. Interprovincial connections can thus constitute transmission capacity between two provincial grids in the same region or each of the six grid regions.

From 2020 to 2060, total interprovincial grid capacity within different regions is expanded 627GW amounting to 166 % increase In BLS1, 894 GW amounting to 237 % increase in the CNS1, and 593 GW amounting to 157 % increase in the CNS2, from 377 GW in 2020.

Interregional power transmission has similar trends as interregional grid capacity and the growth is even sharper. In BLS1, the power transmission is expanded from 760GW in 2020 to 2681 GW in 2060, amounting to 253 % increase. The corresponding growth is sharper in the CNS1 and CNS2. The size of overall power transmission in 2060 is more than 4 times in the CNS1 and CNS2, compared to the number in 2020.

Figure 5-22: Interprovincial grid capacity within the same regional grid In BLS1 (left column) and CNS1 (middle column) and CNS2 (right column)

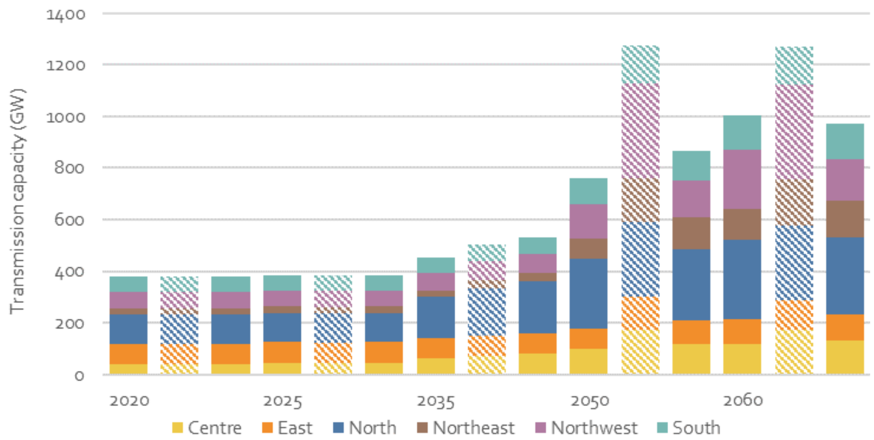
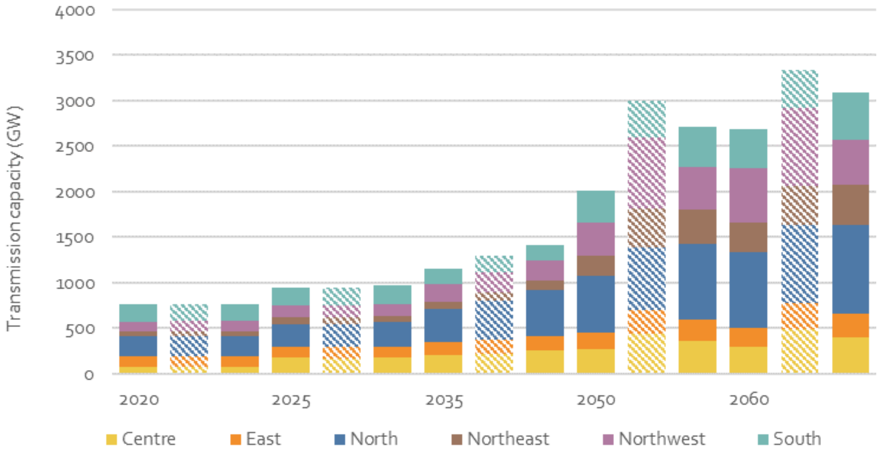


Figure 5-23: Interregional grid capacity In BLS1 (left column) and CNS1 (middle column) and CNS2 (right column)



Power transmission between regions

Grid development was previously driven by electricity demand growth, but in the future increasing penetration of renewables will require more frequent and larger sized balancing resources. It is also reflected by the following figures.

Interregional transmission's substantial growth indicates the need to improve interconnection among regional grids. China's current load centres are in the north, central, and east, whereas renewable energy bases are mainly in the northwest, northeast, north and centre, with hydropower mainly in Sichuan and Yunnan. In the long term, less developed but populated regions, such as in Central China, will experience higher shares of electricity demand growth. Increased transmission allows better integration of renewable energy into the grid and balancing over a larger area, enabling greater energy efficiency system wide. Therefore, increased transmission capacity is needed to support regional demand growth as well as integration of renewables.

Figure 5-24: Power transmission between regions in 2025

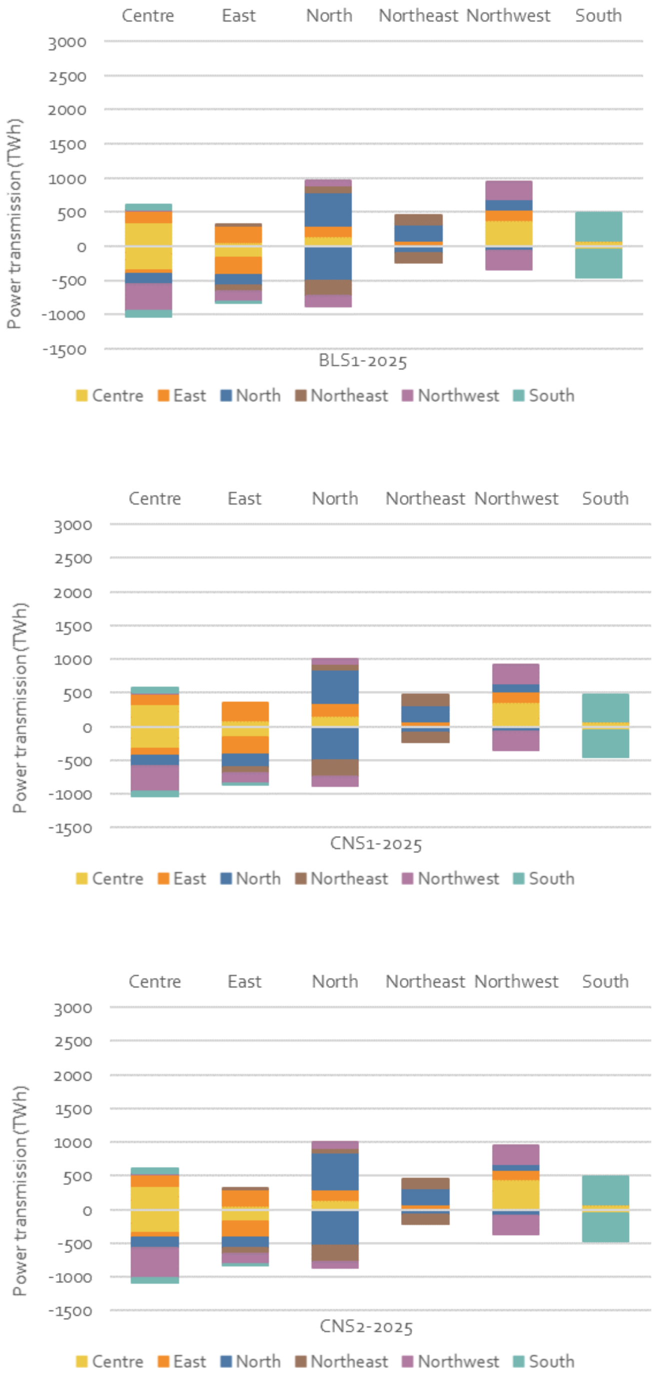


Figure 5-25: Power transmission between regions in 2035

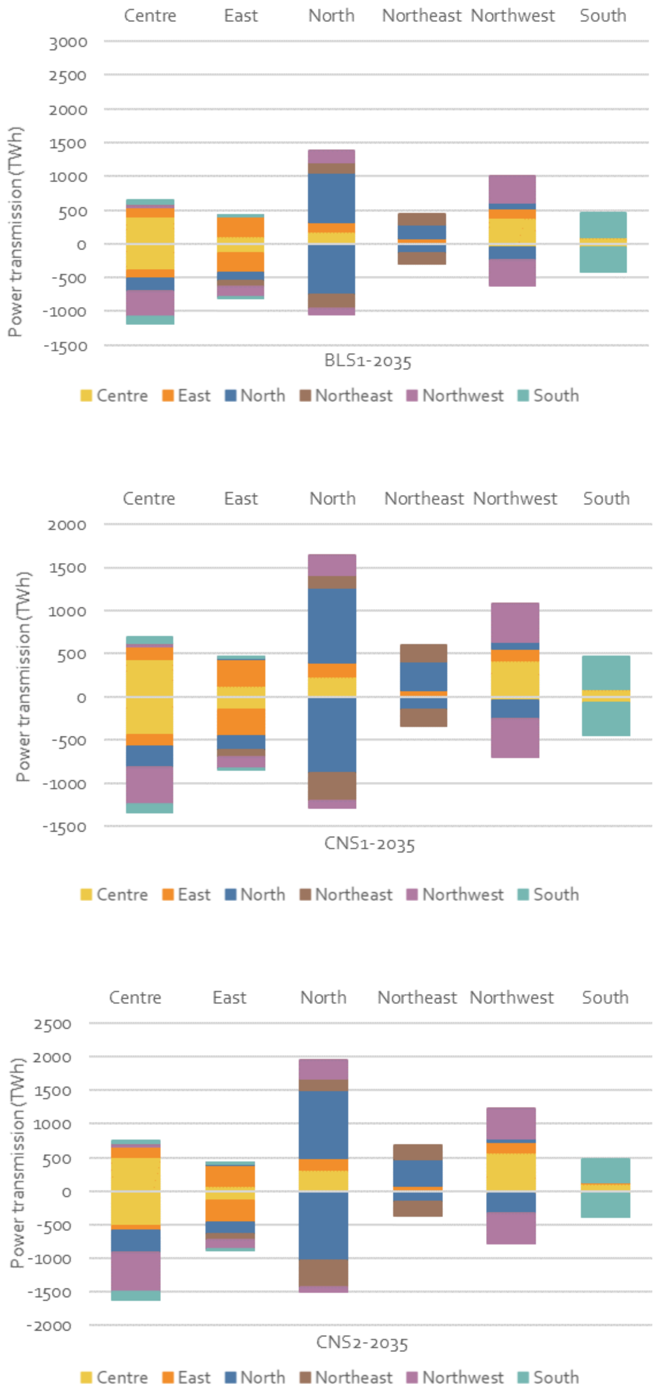
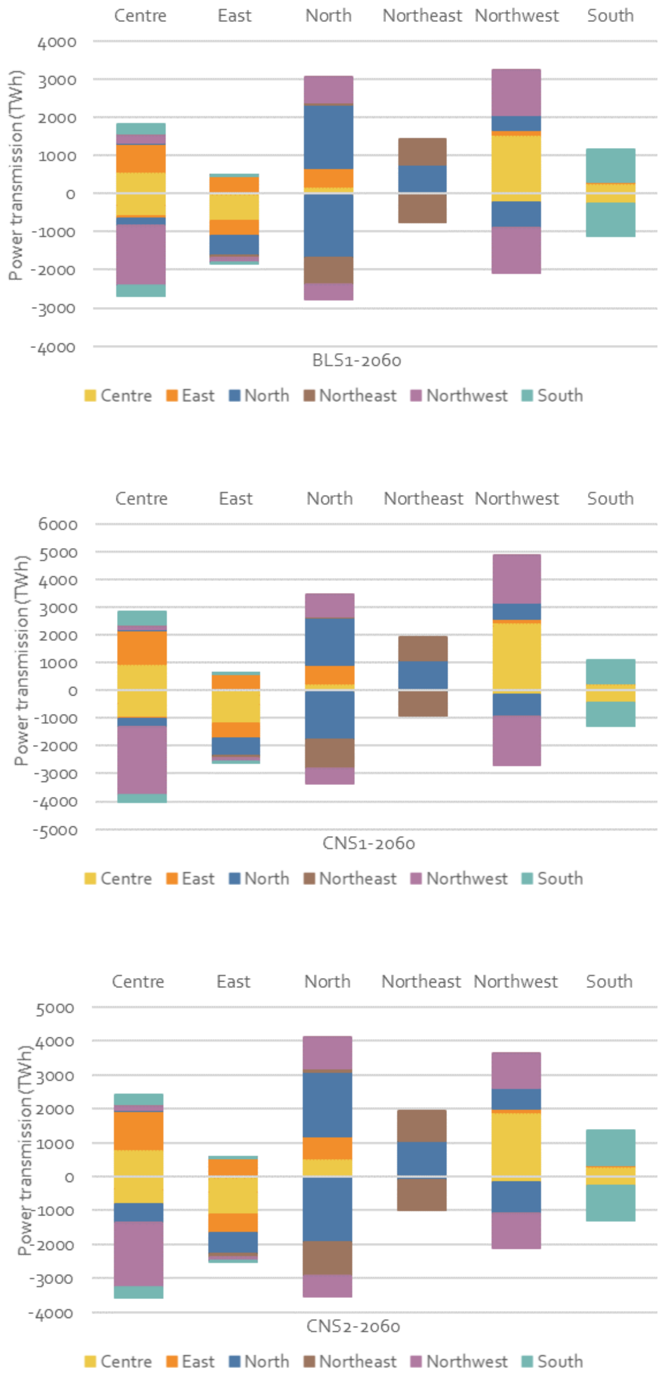


Figure 5-26: Power transmission between regions in 2060



Power grid mid-to long-term development planning

In the model, transmission grid expansion is planned according to least-cost principles in order to efficiently transfer electricity and ensure system security. In the short term, it is assumed that all lines currently planned or under construction will be completed. After 2020, new lines are added to support electricity demand growth and integrate more renewables in the power system. In the future, more new lines are added to support electricity demand growth and integrate more renewables in the power system. Furthermore, a power grid that has a good network structure and dynamic grid operation is an important form of flexibility, which is sometimes overlooked. It is very important that grid planning process includes the perspectives from market development so that the system operation can maximise the overall societal good. The cost-benefit analysis should consider the integration of renewable energy as well as other forms of generation or consumption, but not just the generation growth of electricity demand.

Current status of grid infrastructure development

- Transmission grid expansion is critical to ensure stability and balancing support, especially when the grid needs to integrate a high proportion of variable renewable energy. As of the end of 2020, China's total length of transmission lines with a voltage of 220 kV or above in China reached 794,000 km, including 748,000 km of AC lines and 46,000 km of DC lines. The 185 cross-regional and cross-provincial AC transmission lines with a voltage of 330 kV or above, have a combined length of 32,150 km; and the 32 DC transmission lines have a combined length of 44,633 km.
- In terms of power capacity, as of 2020, China's total capacity of substation equipment with a voltage of 220 kV and above is 4.53 billion kVA, including 4.10 billion kVA of AC substation equipment capacity and 430 million kVA of DC converter capacity.
- In terms of grid structure, China's national grid consists of six regional grids, i.e. Northeast, North, Northwest, East, Central and Southern Grids, whereas the Northeast Grid is based on a 500 kV main network structure; the North China Grid, based on AC UHV lines, forms a "two horizontal, three vertical and one ring-shaped" network structure; the Northwest Grid is based on a 750 kV main network structure; the East China Grid is based on a 1000 kV UHV ring-shaped main network structure; the grids of four Central and East China provinces and Sichuan, Chongqing and Tibetan Grids have achieved asynchronous interconnections; Sichuan and Chongqing Grids and the Central Tibetan Grid are interconnected based on 550 kV lines; and the Southern China Power Grid forms a main network structure characterized by "eight AC and ten DC lines".

Development vision and key tasks in different phases

In view of the current status and long-term goal of China's power grid construction and development, the medium to long-term power grid development plan is broken down into three major phases of implementation.

- From 2021 to 2025: it is a near-term development phase, during which China's power grid development mainly focuses on addressing incoherence between power grid and power supply development, and therefore to better align power grid development with power supply layout.
- From 2026 to 2035: it is a medium-term development phase, during which the focus of China's power grid development is to address the economic efficiency aspects of power grid, and to build a power grid system which mainly depends on nearby resources for power generation, supplemented by inter-regional power allocation; aided by such measures as flexibility retrofitting of thermal power plants and power grid mutual assistance, it is ensured that an increasing share of clean and green energy is integrated and helps gradually achieve the goal of placing equal emphasis on centralized and decentralized uses of clean and green energy.
- From 2036 to 2060: it is a long-term development phase, during which the focus is to comprehensively build an economy-friendly, adaptation-friendly, and environment-friendly modern power grid system, with the main emphasis placed on establishing robust trans-regional interconnections, a reasonable power grid structure across different provinces and cities, and full intellectualization of power grids at all levels.

Plan targets and main characteristics of power grid

By 2025, all Chinese provinces and cities are fully covered by UHV grids, with grids at all levels continuously improved, and development of cross-provincial and cross-regional grids continuing at an accelerated pace; distribution grids witness rapid development, aided by wide application of key intelligent technologies and equipment. Continuous improvements are made with respect to the connection adaptability of distributed energy sources, such as wind and solar. And power supply capacity and reliability is significantly enhanced. Renewable energy, e.g. wind and solar power generated in western and northern regions, and hydropower generated in the southwestern region, are connected to neighboring provinces and cities through multi-circuit transmission channels, so as to meet their power demand and the need for substitution of fossil fuel consumption; on the other hand, direct connection between utility-scale energy generation bases in the west, north and southwest and eastern and central load centers through cross-regional transmission channels may help ease the power transmission demands of large coal and renewable power generation bases. Scheduling methods and trading mechanisms are constantly adjusted, and the potential of cross-provincial and cross-regional grid flexibility capacity being exploited, albeit in varying degrees. With the advances in flexibility transformation pilot schemes and the gradual establishment of relevant market-oriented mechanisms; power regulation potentials are deeply exploited; meanwhile, demand-side management gains increasing attention, which ensures higher proportions of renewable energy, e.g. wind and solar power, into the power grid.

By 2035, all Chinese provinces and cities are covered by reliable and efficient UHV grids, with grids reasonably developed and distributed at all levels; affected by balanced economic development and power distribution optimization, while development of cross-provincial and cross-regional grids gradually slows down, the capacity of flexible mutual assistance is constantly improved; as the distribution grid structure is further strengthened, intellectualization is basically realized in all relevant links, with the level of power supply capacity and reliability raised to a new height. Renewable energy, e.g. wind and solar power, generated in the western and northern regions is utilized both locally and cross-regionally; hydropower in the southwest and Tibet is delivered to other regions on a large scale through transmission channels. The distributed energy system is expected to become a major force for centralized power supply in the large power network. Most thermal power plants in China have completed flexibility transformation, and the "VPPs" resulting from power demand-side management participate as flexibility resources in grid dispatching. The power grid, which forms a close connection between large power bases, distributed power sources, end-users and load centers, has non-blocking transmission capability and is capable of providing services as a smooth, efficient, safe and stable foundation and platform for power market transactions, and of enabling the optimal allocation of energy resources nationwide. Following the establishment of a fully competitive power market and the removal of systematic and institutional barriers for power dispatching and trading, power can be freely traded and delivered cross-provincially and cross-regionally, and reliability and flexibility of the power grid is significantly improved.

By 2060, a modern grid system that is economy-friendly, adaptation-friendly and environment-friendly is put in place in China. Relying on flexible grid technologies and innovative systems and mechanisms, the main and distribution networks are being developed in a coordinated manner, and equal emphasis is placed on both centralized and decentralized utilization of all types of power generation resources. While a majority of energy resources are utilized in local areas, the rest may be delivered cross-regionally to meet the demands of other areas; while renewable energy is given a priority, fossil fuels, such as coal and natural gas, will be transformed as important means of regulation; demand-side management will play a key role. With the aid of the local flexible transmission network, abundant renewable resources in the northwestern and northeastern regions are not only fully utilized locally, surplus resources can also be delivered to North, Central and East China through cross-provincial or cross-regional transmission channels; not only utility-scale hydropower and wind power generated in the south is utilized locally by large load centers within the region, e.g. Guangdong and Shenzhen, but also the surplus electricity can be delivered to Central and East China; Central China will emerge as a transit of China's electric energy to transmit surplus clean and green energy generated in various regions to North, East and South China.

Part 3: Thematic analyses

6 Power-to-X in the Chinese energy system

Power-to-X encompasses numerous energy conversion pathways which take electricity as an input to produce a broad range of fuels, energy forms, chemicals and even food products. Deriving these fuels and products from electricity is motivated by the possibility to reduce their CO_2 intensities as well as reduce dependence on fossil fuel-based imports. As the costs of renewable electricity continue to fall, PtX products based on renewable electricity will provide an increasingly cost-efficient way of reducing CO_2 emissions in sectors, in which direct electrification is impossible and/or prohibitively expensive.

In CETO, the following comparative study investigates how the energy systems in two provinces could serve as a PtX production base and which factors are important to consider for PtX to be effective in decarbonising the energy system. Qinghai is chosen to represent a province with considerable VRE resources and with large potential to deploy these at low cost. Guangdong is chosen as it is a load centre, industrial hub, aviation hub, and not least a key location for international shipping. Additionally, Guangdong has hydrogen development included in its 14th FYP with a focus on "clean-energy-based" hydrogen production and chemical by-product hydrogen sources. The analysis is carried out by integrating OptiFlow, an open-source module representing networks of interconnected processes, into the China Energy Supply Optimization (CESO) model which represents the power and district heating supply in the CETO scenarios.

6.1 Key messages

- Even future PtX conversion pathways are likely to involve conversion losses between 25-35% which significantly increases demand for electricity and heat.
  - Consequently, to effectively reduce CO_2 emissions, decarbonised electricity must be used for PtX.
  - Additionally, PtX fuels should not be used in sectors where direct electrification is economically feasible.
- When including upstream emissions, fossil fuels displaced by PtX fuels vary greatly in their CO_2 intensities.
- From a CO_2 emission reduction standpoint, it is necessary to prioritise PtX fuels' utilisation, which requires a system approach considering the above points.
- Initial analysis suggests a CO_2 abatement cost associated with producing and utilising PtX fuels rather than their fossil fuel counterparts in the range approaching 1,500 RMB/tonne for the period 2030-2060. However, this is considered to be sensitive to for example PtX production capacity, cost of traditional fuels and properties of the power system, hence further analysis is needed to understand the range of abatement cost.
- Different provinces require different solutions; the comparative study of two provinces shows that:

- A province's resources, access to biogenic carbon, power system characteristics, and a market for PtX fuels are relevant for which PtX products should be prioritised.
- To reduce CO2 emissions, largescale PtX production should not be built in a province until it can be assured that the electricity demand can be met by CO_2 free sources.

PtX solutions can deliver a cost-effective tool in decarbonising the energy system. The above findings underscore the need for taking a system perspective in the decarbonisation effort, with PtX pathways being reserved for sectors that cannot be directly electrified. Quantitative studies are required to guide 1) Where and when to build large scale PtX facilities, and 2) Prioritise and quantify the different PtX products based on the CO_2 intensity of the fuels they replace.

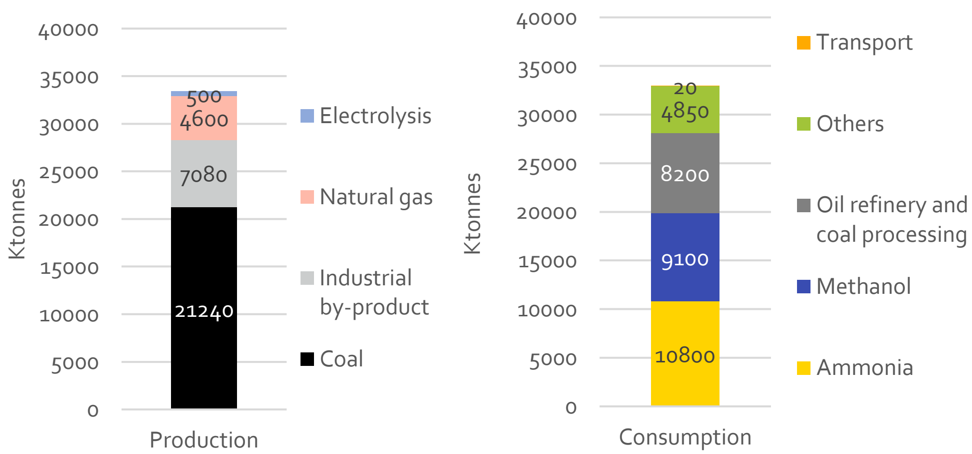
6.2 PtX in a Chinese context

China is currently the world's largest producer and consumer of hydrogen with further ambitions to build a strong hydrogen energy industry. With an emphasis on production, this section will briefly introduce the status of PtX in China along with a perspective on the potential future role of the different PtX routes in a low-carbon energy system.

Hydrogen production routes and their future role in the energy system

At present, China's hydrogen production capacity is approximately 41 million tonnes with an output of 33.42 million tonnes per annum in 2019. Hydrogen is primarily produced from fossil fuels in Northwest, North and East China.

Figure 6-1: Chinese hydrogen production and consumption in 2019



Source: China Hydrogen Alliance

Of total hydrogen production, 21.24 million tonnes are produced from coal, 4.6 million tonnes are produced from natural gas, and 7.08 million tonnes are by-products from industry. Currently, around 500,000 tonnes of hydrogen are produced by electrolysis, and hence RE production only accounts for a small share of total production as can be seen Figure 6-1.

Fossil routes: coal and natural gas

Coal-to-hydrogen is currently the main hydrogen production method in China as the technology is mature, commercialised and has clear cost advantages with production cost ranging 7-12 RMB/kg. It is suitable for large-scale hydrogen production and benefits from abundant domestic coal resources. However, its disadvantages of significant carbon emissions and gas impurities make it incompatible with a future low carbon energy system.

The cost of hydrogen production from natural gas is greatly affected by the price of raw materials, and as China heavily relies on imports of natural gas, the supply is relatively difficult to guarantee. It is primarily suitable for large-scale hydrogen production, and the overall cost is slightly higher than that of hydrogen produced from coal. Similar to coal gasification, its high emissions diminish its role in the future energy system.

Although carbon capture technology might solve the problem of CO_2 emissions in the future, it will significantly increase the cost of hydrogen production reducing its cost competitiveness. In addition, there are many gas impurities associated with fossil fuel-based hydrogen production. If it is to be used in fuel cells, further purification is required, which increases the purification cost.

Industrial by-product hydrogen

Industrial by-product hydrogen refers to a production method that uses industrial tail gas containing hydrogen as a raw material to produce hydrogen. Industrial tail gas is typically chlor-alkali industrial by-product gas, coal chemical coke oven gas, tail gas from synthetic ammonia, and refinery by-product tail gas, etc., i.e. a mixture of gases. Purification and recycling of hydrogen improve resource efficiency, can bring economic benefits, and reduce air pollution.

At present, the commonly used technology for purification is pressure swing adsorption technology (PSA). The PSA hydrogen extraction process is simple, and the technology is mature and currently used for hydrogen production from coke oven gas and hydrogen production from chlor-alkali tail gas. Although the purification process for industrial by-product hydrogen is relatively complicated, it has the advantages of being a low-cost mature technology and has lower emissions relative to the aforementioned fossil routes. It is therefore expected to become an important source of high-purity hydrogen in the future. Including the cost of hydrogen purification, it still has a high-cost advantage (10-20 RMB/kg) compared to electrolysis-based hydrogen.

Electrolysis

Hydrogen production via water electrolysis is a mature technology and the hydrogen purity is high. Despite its current high cost, due to its potential for low or even zero emissions depending on the carbon intensity of the power input, electrolysis is expected to be the main technology used for producing hydrogen in the future.

Electrolysis technologies producing hydrogen include alkaline electrolysis of water, solid proton exchange membrane electrolysis (SPE), and solid oxide electrolysis (SOEC). The alkaline electrolysis technology has long been mature in China, and it is the main domestic hydrogen production method at this stage. The process is simple, the scale of hydrogen production is flexible, and the purity of hydrogen products is high.

SPE hydrogen production technology is still in the research and development stage in China. The price of SPE hydrogen production equipment is several times higher than that of alkaline water electrolysis. However, it has the ability to respond quickly to load changes, and hence is more suitable to supply flexibility services for integration of variable renewable energy power generation. If the equipment cost is reduced, it is a highly promising technology for future hydrogen production.

In general, the total cost of hydrogen production via electrolysis is relatively high due to the current electricity prices. In China, production of 1 kg of hydrogen consumes around 55 to 60 kWh of electricity and hence it is currently difficult to produce hydrogen at a cost below 30 RMB/kg. The high cost of hydrogen production currently limits the large-scale promotion of electrolysis. As the cost of electrolysis equipment, wind power, and solar power continues to decrease, the cost of green hydrogen is expected to decrease from the current 30 RMB/kg to 10 RMB/kg by 2040.

Current and future final product and markets

As shown in Table 6-1, in China, hydrogen is currently mainly used in the chemical industry as intermediate products such as ammonia and methanol which are further used to produce nitrogenous fertiliser, plastics, and rubber.

Table 6-1: Hydrogen final consumption

Product	Annual hydrogen consumption	Share of final hydrogen consumption
Synthetic ammonia	10.8 million tonnes/year	32.3%
Methanol hydrogen (coal-to-methanol-to-olefins)	9.1 million tonnes/year	27.2%
Petroleum refining and coal chemical hydrogen	8.2 million tonnes/year	24.5%
Others, such as hydrogen used in transportation and other industries.	5.3 million tonnes/year	16%

Currently, it is widely recognised that the electrification of end-use energy is the main means to achieving carbon neutrality by 2060. As a result, the share of electricity consumption in total final energy consumption is expected to exceed 70%. This includes electrification of road transportation, construction, and industrial low-temperature heating. However, high-energy-consuming sectors such as heavy-duty freight, aviation, metallurgy, and chemical industries are difficult to directly electrify due to limitations in the gravimetric and volumetric energy densities of mobile energy storage technologies or the demand for industrial raw materials. Compared to electrochemical storage technologies, hydrogen has a higher volumetric and gravimetric energy density and can be combined with CO_2 to synthesise raw materials or fuels with properties similar to those of fossil fuels. This makes hydrogen a secondary energy source with great development potential in hard to electrify sectors.

In summary, hydrogen production in China still mainly relies on fossil energy with the market share of coal-to-hydrogen technology exceeding 60% due to its matureness and low cost. To realise the large-scale transition to green hydrogen, the cost of hydrogen production by electrolysis of water needs to be reduced to 10 RMB/kg, and the cost of hydrogen storage and transportation needs to be reduced to below 5 RMB/kg. Reducing the production cost of green hydrogen to unlock its market competitiveness in the end-use hydrogen industry has therefore become a top priority for the development of China's hydrogen energy industry.

6.3 Introduction to a study comparing two provinces

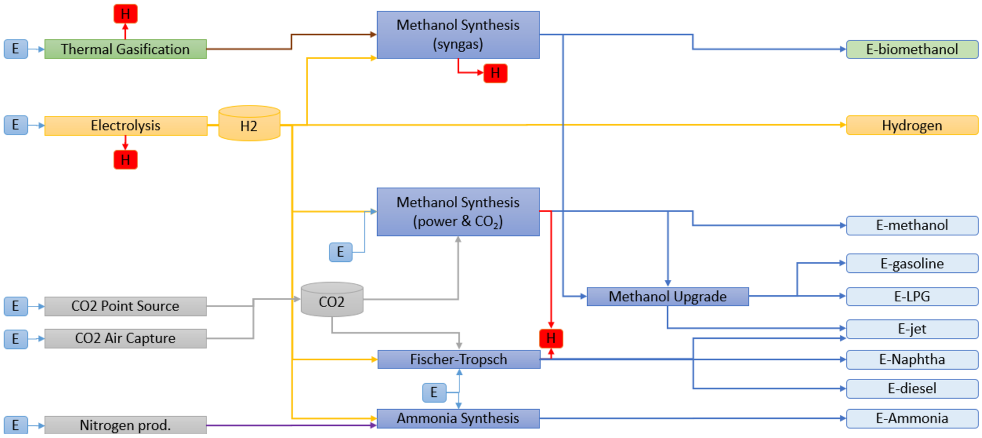
Choice of Xs and processes for evaluation

Power-to-X, commonly referred to as PtX or P2X, encompasses numerous energy conversion pathways taking electricity as an input and a range of output fuels, energy forms, chemicals and even foods. The range of PtX outputs are quite broad and therefore represented by the "X" in the terminology. This analysis focusses on a series of Xs that are deemed to have the potential to contribute to China's vision of being CO_2 neutral by 2060:

- Hydrogen
- E-biomethanol (biomass & hydrogen as input fuels)
- E-methanol (hydrogen & captured CO2 as inputs)
- E-gasoline (hydrogen & captured CO2 or biomass as inputs)
- E-LPG (hydrogen & captured CO2 or biomass inputs)
- E-jet fuel (hydrogen & captured CO2 or biomass as inputs)
- E-diesel (hydrogen & captured CO2 as inputs)
- E- ammonia (hydrogen & nitrogen as inputs)

These fuels, and their renewable energy production pathways are displayed in Figure 6-2.

Figure 6-2: Renewable and power-based fuel production pathways

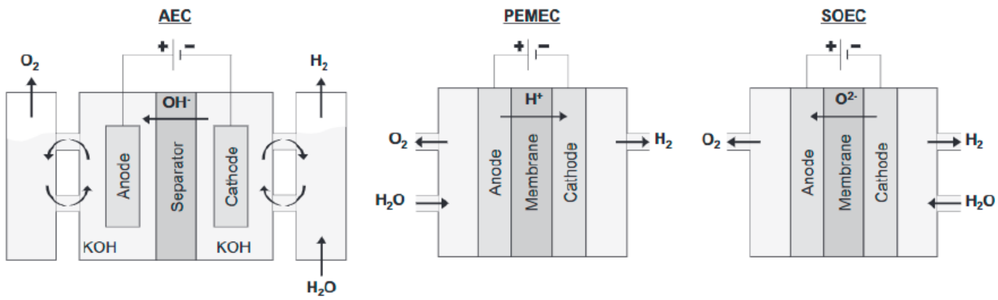


Source: Adapted from M.S. Lester et al., 2020. [51] *Light green boxes indicate a biomass fuel input, while light blue output fuels rely solely on electricity, electricity-based hydrogen, and heat as fuel inputs. Red box with H and blue box with E represents heat and electricity respectively.*

Hydrogen

Renewable hydrogen is produced via electrolysis, of which there are three primary types represented in the current analysis: alkaline (AEC), polymer electrolyte membrane (PEM) and solid oxide electrolysis (SOEC). While all three technologies rely on water splitting by electricity and the reaction $2H_2O \rightarrow 2H_2 + O_2$, the operating principles vary (see Figure 6-3)

Figure 6-3: Operating principles for AEC, PEM and SOEC



Source: Danish Energy Agency, June 2017 (updated April 2021). [52]

AECs are the most mature of the three technologies and as they currently have the lowest hydrogen production costs, they are the most common commercially available electrolyser. SOECs have the potential to produce hydrogen more efficiently than AECs, and via co-electrolysis (conversion of CO_2 and steam simultaneously) and hence may be better suited for hydrogen destined for use in production of methanol. However, SOECs must first demonstrate that they can operate at largescale and overcome issues related to short stack lifetimes. Table 6-2 highlights some of the main aspects and potential advantages and disadvantages of the three electrolysis technologies in focus here.

Table 6-2: Energy balances, regulation ability, and summary of advantages/disadvantages of the three selected electrolysis technologies

		AEC	PEM	SOEC
Energy Balance (in 2020)	Input	• Electricity: 100%	• Electricity: 100%	• Electricity: 79.5% • Heat: 20.5%
	Outputs (LHV*)	• H_2: 66.5% • Useable heat: 16.4% • HHV-LHV: 12.1% • Losses: 5.0%	• H_2: 58.0% • Useable Heat: 26.4% • HHV-LHV: 10.6% • Losses: 5.0%	• H_2: 77.5% • HHV-LHV: 14.1% • Losses: 8.4%
Regulation ability (2020)	Cold start (minutes)	<120	10 (5-10)	720 (680-880)
	Warm start (seconds)	240 (60-300)	<10	900
Financial aspects** (2020)	CAPEX***	5.0 Mio. RMB / MW input$_{el}$	7.0 Mio. RMB / MW input$_{el}$	36 Mio. RMB / MW input$_{el}$
	Fixed O&M	2% of initial CAPEX per year	4% of initial CAPEX per year	12% of initial CAPEX per year
	Lifetime	25	20	10
Advantages		• Mature technology • Long stack life • Lowest production cost • Large-scale systems already in operation	• Can (not without challenges) produce pressurised H_2 • Large-scale systems already in operation	• Highest electricity conversion efficiency • Can make synthesis gas from co-electrolysis of steam and CO_2
Disadvantages		• Use of highly caustic electrolyte • Leakage of KOH	• Requires very pure input water • Catalyst is expensive and scarce • Modules are expensive	• Large-scale facilities still in demonstration phase • Short stack life • Stack components susceptible to corrosion

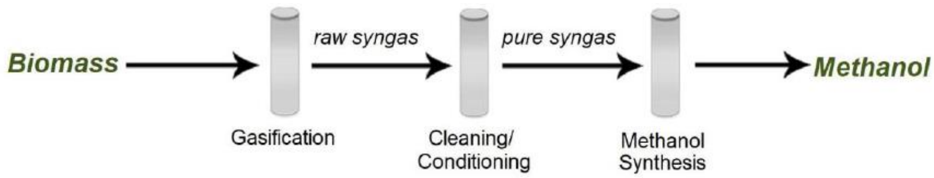
** Comparisons are provided on a Lower Heating Value (LHV) basis, while "HHV-LHV" represents the difference between the higher and lower heating values.*
*** SOEC is not yet commercially available, particularly at a MW level, and thus all cost figure estimates are highly uncertain.*
**** Note that all prices listed are taken from a Danish source. CAPEX may be considerably lower in a Chinese context.*
Source: Danish Energy Agency, June 2017 (updated April 2021).[53]

Methanol

There are a variety of ways of producing methanol from renewable fuels and the two selected for the current analysis are methanol synthesis via biomass gasification, and methanol synthesis with hydrogen and captured CO_2 as the primary inputs.

The basic biomass to methanol process via gasification is displayed in Figure 6-4. In the first step the solid biomass is converted into a bio-syngas, which is then cleansed, before this syngas is further converted into refined methanol.

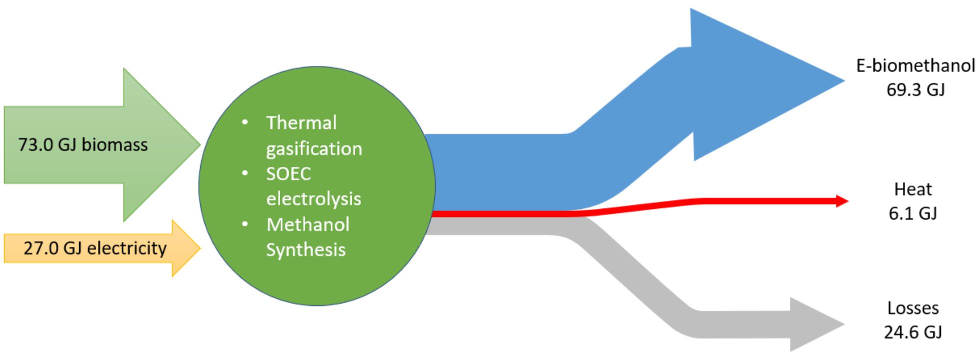
Figure 6-4: Biomass to Methanol Process



Source: Danish Energy Agency, June 2017 (updated April 2021).[54]

Depending on the configuration, the exothermic reactions generate enough heat for the overall process and can also produce the required electricity to sustain production, thus resulting in the only input being raw biomass. Meanwhile, other configurations require some input electricity (roughly 11% of the energy input). The focus of this analysis is a configuration where hydrogen is also added, thus resulting in a carbon to hydrogen ratio that better suits methanol synthesis. This configuration is sometimes referred to as "hybrid biomass to methanol", and the energy balance for the selected plant in the current analysis is displayed in Figure 6-5.

Figure 6-5: Hybrid Biomass to Methanol Plant energy balance - 2050

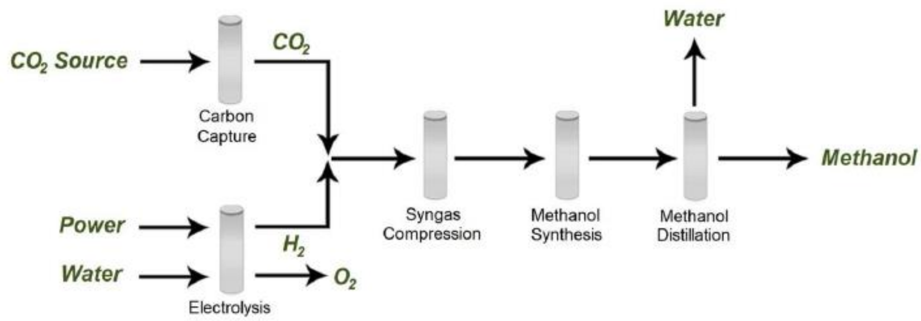


Source: Danish Energy Agency, June 2017 (updated April 2021).[55] *& M.S. Lester et al., 2020.* [56]

As was alluded to in the previous section, under the assumption that it can be developed at a large scale, in the longer term, SOEC may be the preferred form of electrolysis for a "hybrid biomass to methanol plant" as it can produce synthesis gas from co-electrolysis of steam and CO_2. Given the required biomass inputs, the methanol produced via this process is referred to as e-biomethanol throughout this report.

Meanwhile, Figure 6-6 illustrates what is referred to here as e-methanol, which is derived via the power to methanol process, and requires CO_2 and H_2 as inputs.

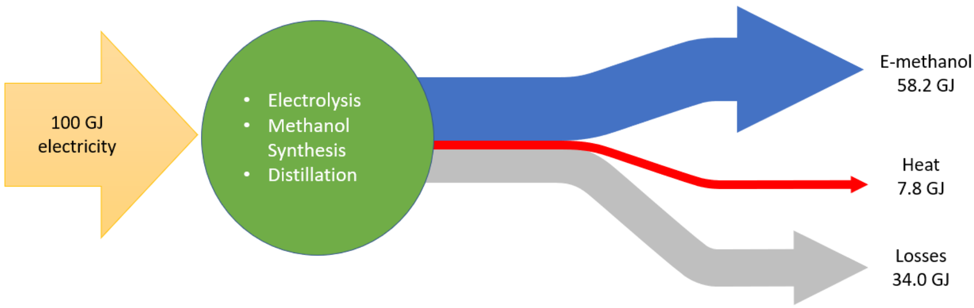
Figure 6-6: Power to Methanol process



Source: Danish Energy Agency, June 2017 (updated April 2021).[57]

The energy balance for the power to methanol process varies depending on how the carbon is captured[3], what kind of electrolyser is used, and the extent to which heat can be recuperated and utilised. In a process where some of the waste heat is used internally for CO_2 capture, then 100 MJ of electricity input is expected to produce roughly 58 MJ of refined methanol as shown in Figure 6-7.

Figure 6-7: Power to Methanol Plant energy balance - 2050



Methanol upgrading

With renewable methanol as an input, it is possible to upgrade the methanol and produce the following PtX fuels:

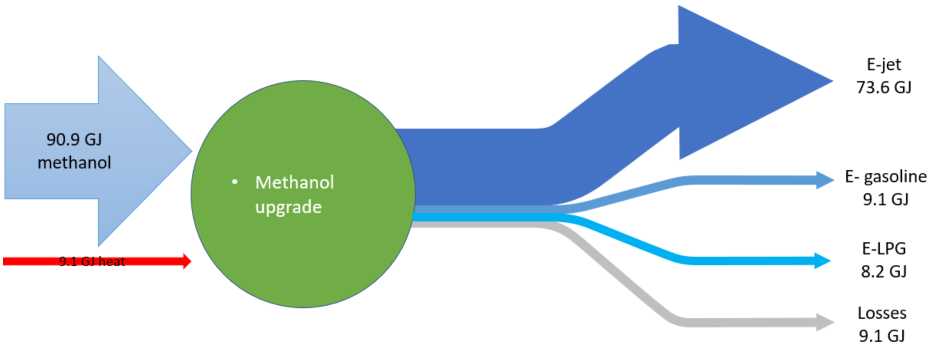
- E-gasoline
- E-LPG
- E-jet fuel

The energy balance and resulting distribution of output fuels assumed in the current study are based on M.S. Lester et al., 2020[58], and are displayed in Figure 6-8. Note that the

[3] There are two primary options for carbon capture included in the current analysis: at a power plant or via direct air capture. However, other sources, e.g. from industrial plants, are also relevant to consider.

selected process is optimised for jet fuel production, but if some of the other fuels were deemed to be more relevant, it could also be optimised to produce these in greater quantities.

Figure 6-8: Methanol upgrade energy balance - 2050



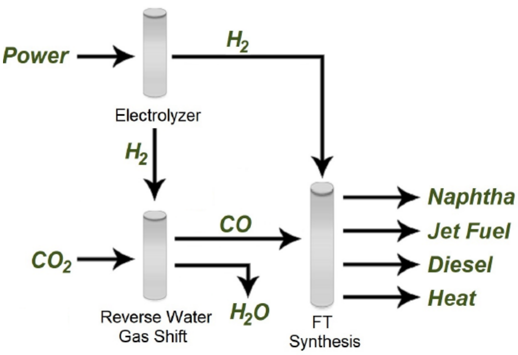
Source: M.S. Lester et al., 2020. [59]

Fischer–Tropsch fuels with H_2 & CO_2 as inputs

Another pathway for producing a range of liquid and gaseous e-fuels involves utilising hydrogen and CO via a Fischer-Tropsch (FT) process to produce syncrude or Fischer-Tropsch wax. This output can then be further refined to produce e-jet fuels, e-diesel, e-naphtha, and other e-hydrocarbons. Such a pathway can take many forms depending on the selected electrolysis technology, the CO_2 source, the method for converting CO_2 to CO, or even potentially using the CO_2 directly via an electrochemical process, which is currently being investigated on a small-scale level.

The pathway described here (see Figure 6-9) is the one deemed to be the closest to being commercially available at scale. It consists of alkaline electrolysers to produce hydrogen, captured CO_2, and a reverse water gas shift (RWGS) process to convert CO_2 to CO for use in the Fischer-Tropsch synthesis.

Figure 6-9: Power Fischer–Tropsch fuels process

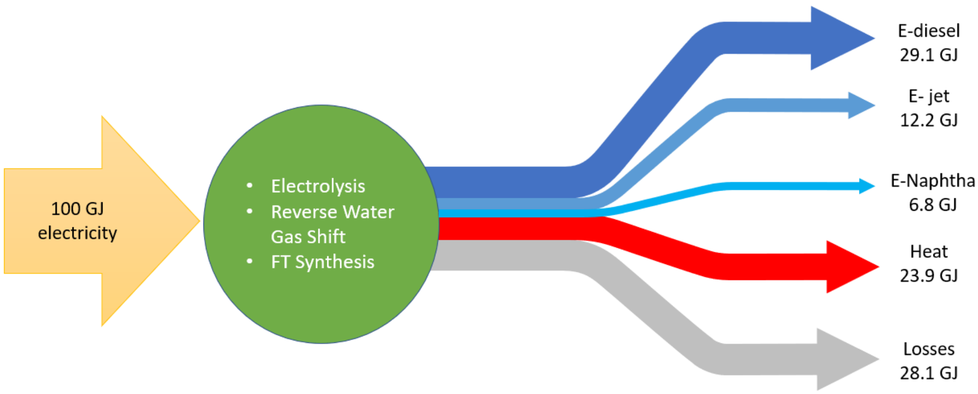


Source: Danish Energy Agency, June 2017 (updated April 2021). [60]

The distribution of output fuels and resulting energy balance for a Fischer-Tropsch synthesis facility can vary greatly depending on which output fuels are prioritised. For example, the Danish technology catalogue contains a projected energy balance for a "power to jet fuel" facility in 2050 where 33% of the input electricity is converted to jet fuel, 22% to other hydrocarbons (includes gaseous hydrocarbons and liquids that are both lighter and heavier than jet fuel), 25% to district heat, and the remaining 20% for internal use and losses. Alternatively, the focus could be on producing a greater proportion of e-diesel.

Within the current analysis e-jet fuel can also be produced via the upgrading of methanol, hence a Fischer-Tropsch process geared to the production of e-diesel has been selected. The assumed energy balance was based on data from the Danish technology catalogue for the above-mentioned Power to Fischer–Tropsch fuels process as well as M.S. Lester et al., 2020.[61] The resulting energy balance is displayed in Figure 6-10.

Figure 6-10: Electrolysis & Fischer Tropsch Energy Balance in 2050



Source: Danish Energy Agency, June 2017 (updated April 2021).62 & M.S. Lester et al., 2020. [63]

Green ammonia synthesis – H2 and Nitrogen

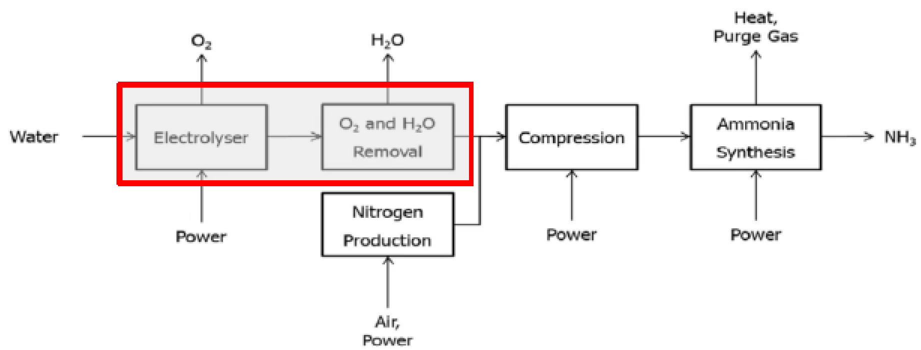
Ammonia is a versatile chemical that forms a key component of the nitrogen-based fertiliser industry. Other uses include a refrigerant for industrial cold storage, applications in the food processing industry, large-scale air-conditioning, production of AdBlue for vehicle NOx control, and other industries such as pharmaceutical, textile and explosives. Conventional ammonia production is a highly energy-intensive process consuming around 1.8% of annual global energy output and emitting around 500 million tonnes of CO_2 corresponding to 1.8% of global CO_2 emissions[64]. Therefore, decarbonising ammonia production is a key concern for the industrial sector.

The industrial process through which nitrogen gas and hydrogen gas are converted into ammonia is called the Haber-Bosch process. Currently this process predominantly uses fossil fuels, air, and water as inputs. Natural gas is typically used as the fossil fuel followed by coal, heavy fuel oil or vacuum residue. Different types of ammonia can be categorised based on production process, as follows:

- Brown ammonia: made using a fossil fuel as the feedstock
- Blue ammonia: brown ammonia but with carbon capture and storage technology applied to the manufacturing processes.
- Green ammonia: made using renewable energy, water and air.

While the ammonia produced is the same in each case, the carbon emissions from the processes differ. The CO_2 emissions from brown ammonia is highest, and lowest from green ammonia (based on the share of renewable energy used in the process). The focus in this study, therefore, is on green ammonia production as a decarbonisation solution.

Figure 6-11: Green Ammonia plant



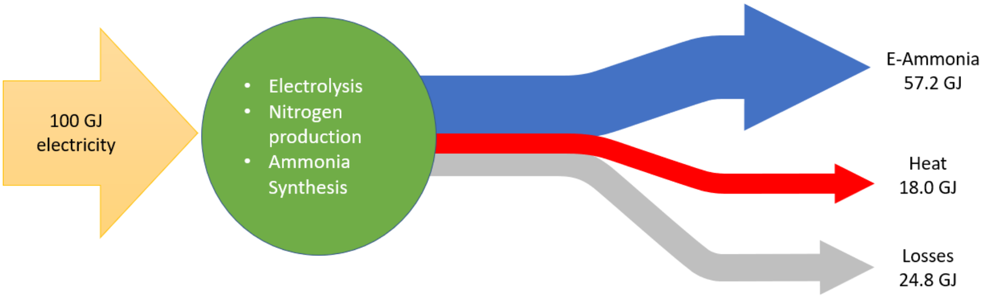
Source: Danish Energy Agency, June 2017 (updated April 2021).65 & M.S. Lester et al., 2020. [66]

The industrial production of ammonia can be divided into two major stages: the manufacture of hydrogen and the synthesis of ammonia, as seen in Figure 6-11. The hydrogen production stage accounts for ~90% of the emissions in the conventional process. For green ammonia synthesis, hydrogen is produced through water electrolysis. Nitrogen is obtained directly from air using an air separation unit which accounts for a negligible share of the process energy used. The hydrogen and nitrogen serve as main inputs to the synthesis of ammonia. This is the Haber-Bosch process described by the below equation with Q representing heat:

$$3H_2 + N_2 \rightarrow 2NH_3 + Q$$

This ammonia reaction is highly exothermic and the heat released is therefore used to generate steam. The steam generated is an export from the ammonia synthesis loop. The energy balance for AEC electrolysis & ammonia synthesis is displayed in Figure 6-12.

Figure 6-12: Electrolysis & Ammonia Synthesis Energy Balance in 2050



Source: Danish Energy Agency, June 2017 (updated April 2021).67 & M.S. Lester et al., 2020. [68]

Table 6-3: Summary of key pathways and processes

Pathway	Inputs	Processes	Outputs	Efficiency (2050)	
				Total	Excl. output heat
Hybrid biomass to methanol	• Biomass • Electricity	• Thermal gasification • Electrolysis • Methanol synthesis	• E-biomethanol • Useable heat	75%	69%
Power to methanol	• Electricity • CO_2	• Electrolysis • Methanol synthesis	• E-methanol • Useable heat	66%*	58%*
Methanol upgrade	• Methanol • Heat	• Methanol upgrading	• E-jet fuel • E-gasoline • E-LPG	91%	91%
Electrolysis & Fischer Tropsch	• Electricity • CO_2	• Electrolysis • RWGS • FT synthesis	• E-diesel • E-jet fuel • E-naphtha • Useable heat	72%*	48%*
Electrolysis & Ammonia Synthesis	• Electricity	• Electrolysis • Nitrogen production • Ammonia synthesis	• E-ammonia • Useable heat	75%	57%

** Exclude the energy required to capture CO_2*

The primary processes, inputs, outputs, and efficiencies for the key PtX pathways investigated in the study are summarised in Table 6-3 .The table highlights the losses associated with PtX pathways, which despite efficiency improvements over the next decades, are anticipated to still be significant in 2050. As a result, PtX fuels should be reserved for sectors where direct electrification is not possible. These losses also make it even more important that electricity for PtX production becomes increasingly decarbonised.

CAPEX and Fixed O&M of selected PtX technologies

The cost assumptions presented in the tables below are based on *Danish Energy Agency, June 2017 (updated April 2021)*[69] *& M.S. Lester et al., 2020* [4]. The data from these sources is used as baseline before conversion to RMB. Most of the technologies are still in the development phase so future values reflect the expected cost reductions from increased deployment and technical advancements.

Table 6-4: Investment cost assumptions for processes included in PtX setup

Technology	unit	2030	2040	2050	2060
AEC	MRMB/GJ input el/h	0.95	0.64	0.53	0.53
PEM	MRMB/GJ input el/h	1.38	0.95	0.85	0.85
SOEC	MRMB/GJ input el/h	3.63	1.99	1.65	1.65
Ammonia Synthesis	MRMB/GJ output/h	1.80	1.63	1.48	1.48
CO2 Direct Air Capture	MRMB/tonne/h	22.93	16.08	13.50	13.50
Fischer Tropsch	MRMB/GJ output/h	1.04	1.04	1.04	1.04
Power to Methanol	MRMB/GJ output/h	1.07	1.07	1.07	1.07
Methanol Upgrade	MRMB/GJ output/h	0.67	0.64	0.62	0.62
Hybrid Biomass to Methanol	MRMB/GJ bio input/h	0.45	0.41	0.37	0.37
Thermal Gasification (crop residues, wood)	MRMB/GJ bio input/h	1.62	1.47	1.33	1.33

Table 6-5: Fixed O&M cost assumptions for processes included in PtX setup

Technology	unit	2030	2040	2050	2060
AEC	kRMB/GJ input el/h	19.1	12.7	10.6	10.6
PEM	kRMB/GJ input el/h	55.0	38.1	33.9	33.9
SOEC	kRMB/GJ input el/h	435.8	238.6	197.5	197.5
Ammonia Synthesis	kRMB/GJ output/h	48.3	53.5	59.3	59.3
CO2 Direct Air Capture	kRMB/tonne/h	917.3	643.2	540.1	540.1
Fischer Tropsch	kRMB/GJ output/h	41.7	41.7	41.7	41.7
Power to Methanol	kRMB/GJ output/h	43.0	43.0	43.0	43.0
Methanol Upgrade	kRMB/GJ output/h	24.8	24.8	24.8	24.8
Hybrid Biomass to Methanol	kRMB/GJ bio input/h	13.6	12.4	11.2	11.2
Thermal Gasification (crop residues, wood)	kRMB/GJ bio input/h	64.9	58.9	53.4	53.4

[4] CAPEX and Fixed O&M costs have not yet been adjusted to reflect lower Chinese labour and construction costs. As separate Fixed O&M and Variable O&M costs were not available for all technologies, Variable O&M costs have been included in Fixed O&M.

6.4 Comparative study of PtX – the cases of two Chinese provinces

Production of PtX fuels, as a means of energy system decarbonisation, is interlinked with several energy systems. Hence, producing PtX products efficiently will depend on the local characteristics of these energy systems. For this reason, an analysis has been carried out looking at how the energy systems in two very different provinces in China would serve as a PtX production base.

Guangdong and Qinghai's energy systems

The two provinces chosen for the comparative study are Qinghai and Guangdong.

Qinghai is selected as it is a province with considerable RE resources and with large potential to deploy these at low cost. In the CETO scenarios, Qinghai therefore exports considerable amounts of VRE electricity to load centres east thereof. PtX production could potentially augment this energy export. Additionally, it already has a relatively low share of fossil fuel in its electricity generation of around 33%. In the production of PtX, Qinghai can also benefit from integration with district heating systems, both using heat production facilities to provide heat input to the PtX processes, but also to take advantage of surplus heat produced with PtX.

Guangdong, on the other hand, is a load centre, industrial hub, aviation hub, and not least a key location for international shipping. In short, Guangdong, aspires to be a large consumer of PtX fuels and thus already has hydrogen development included in its 14th five-year plan (FYP) with a focus on "clean-energy-based" hydrogen production and chemical by-product hydrogen sources. However, the renewable capacity potential is limited and currently 62% of its electricity is generated from fossil sources, which limits the capacity to produce low-cost green hydrogen-based fuels and chemicals. Since it is already a net-importer of electricity and has a lack of abundant local low-cost renewables, it will presumably lead to higher cost of local PtX production which should be weighed against new infrastructure and/or shipping costs of bringing PtX fuels to Guangdong's fuel market. Guangdong's coastal location and plans for offshore wind development, however, could potentially go hand in hand with the development of a PtX infrastructure.

Hence, the study looks at two different environments for PtX; one with plentiful of RE potential and one with limited RE resources but closer to the industry and with a potential to integrate with industrial and district heating systems. This will help understand how a large increase in electricity consumption to produce PtX fuels affects different energy systems and the factors affecting the emissions reductions potential of PtX.

Model setup: Optiflow

The quantitative comparative case study is developed using OptiFlow, an open source add-on for Balmorel which has been integrated with the CESO model representing the power and district heating supply in the CETO scenarios. Optiflow is a generalised spatiotemporal network optimisation model which may represent any network flow related to e.g. energy, mass, economy, or emissions. It is a deterministic partial equilibrium model built upon a bottom-up approach that allows for technologies to have multiple inputs and outputs. Technologies are defined as processes while inputs and outputs are defined as flows. Processes can be characterised based on any interacting flow. Storage processes can also be included, which is of high importance when considering flexible production technologies, such as electrolysis.

The add-on is linked to CESO via the electricity, district heating, CO_2, and biomass networks. This allows OptiFlow to simultaneously optimise system costs. In doing so it accounts for changes in electricity price, demands, investments and technical operations of different technologies. All this is subject to defined boundary conditions, such as the surrounding energy system.

Analysis setup: demand and PtX fuel productions

The CETO Baseline scenario is taken as the reference for comparisons of scenarios with and without PtX presented here. The PtX fuel production values shown below for Guangdong and Qinghai provinces are chosen as a share of the estimated national production in the Baseline scenario. The share is chosen to be proportionate to the ratio of renewable energy generated in these provinces with respect to the total renewable generation in China from 2020 to 2060. Within this period, the values of renewable energy share with respect to the country level average to 3% and 4% respectively for Guangdong and Qinghai. These provincial PtX fuel demands are not projections, but an attempt to create relevant and plausible boundary conditions for the exogenous PtX fuel demand inputs to the energy system optimisation based on the CETO Baseline scenario. Hence, these demands are not optimised and should therefore not be seen as suggested outputs from the provinces. They are only set as a fixed demand to investigate how the power system responds.

In the case of hydrogen, demand for hydrogen from sectors such as industry, chemicals, and transport were inputs to the model. Total hydrogen production was therefore comprised of hydrogen for "other" sectors (exogenous demand[5]), and the hydrogen required for input to the PtX processes (endogenously optimised by the model).

[5] This exogenous hydrogen demand from 'other' sectors is covered in Chapter 4.

Table 6-6: PtX fuel production for Guangdong and Qinghai

	E-bio methanol	E-methanol	E-jet fuel*	E-gasoline	E-LPG	E-diesel	E-naphtha	E-ammonia
PtX fuel production – Guangdong (TJ)								
2030	555	555	3,556	368	331	1,370	319	567
2040	922	1,299	8,263	901	811	2,297	535	1,036
2050	1,241	1,942	11,866	1,317	1,186	2,849	664	1,406
2060	1,554	2,591	14,958	1,662	1,495	3,571	832	1,826
PtX fuel production – Qinghai (TJ)								
2030	671	671	4,300	400	360	1,656	386	686
2040	1,114	1,571	9,990	980	882	2,777	647	1,253
2050	1,501	2,347	14,347	1,433	1,290	3,444	803	1,700
2060	1,879	3,132	18,085	1,808	1,627	4,318	1,006	2,207

**Combined total from Methanol upgrade and Fischer–Tropsch*

PtX capacities in Guangdong and Qinghai

Given the demand for the final products indicated in Table 6-6, cost-optimal capacity expansion of the processes are obtained as indicated in Table 6-7. These capacities are co-optimised with the power and district heating supply systems in the CETO model. Production of these PtX fuels requires significant investment in production facilities, particularly electrolysers, as all the pathways in the analysis use hydrogen.

Table 6-7: Model installed capacities (in MW*) for main PtX processes for Guangdong and Qinghai provinces up to 2060

	Guangdong				Qinghai			
	2030	**2040**	**2050**	**2060**	**2030**	**2040**	**2050**	**2060**
Electrolysers (total)	698	2928	3059	2604	831	3669	4272	4185
AEC	698	2730	2288	2032	831	3669	4272	4185
PEM	0	0	0	0	0	0	0	0
SOEC	0	199	771	572	0	0	0	0
Ammonia Synthesis	20	40	56	71	22	45	91	90
Fischer-Tropsch	81	151	243	365	88	269	342	485
Hybrid Biomass to Methanol	129	303	392	507	144	200	183	132
Power to Methanol	20	50	174	182	36	260	565	905
Methanol Upgrade	130	317	466	586	157	396	628	800
CO_2 Direct air capture	49	112	96	0	43	376	730	354

**The capacities are in units of MW-input of electricity for electrolysers and direct air capture, and E-methanol methanol upgrade. For the rest, they are in terms of MW-output of the product.*

Capital intensity of PtX processes leads to high average utilisation rates

The annual full-load hours (FLHs) for the production facilities in the two provinces for 2035 and 2060, as well as the average from 2030 to 2060 are displayed in Table 6-8. All the processes involved in the analysed PtX production pathways are capital intensive, and optimal capacity deployment thus requires high utilisation rates as evidenced by the high number of FLHs. In the model, the electricity prices vary, as shown in Figure 6-14, and this is thus included in the optimisation.

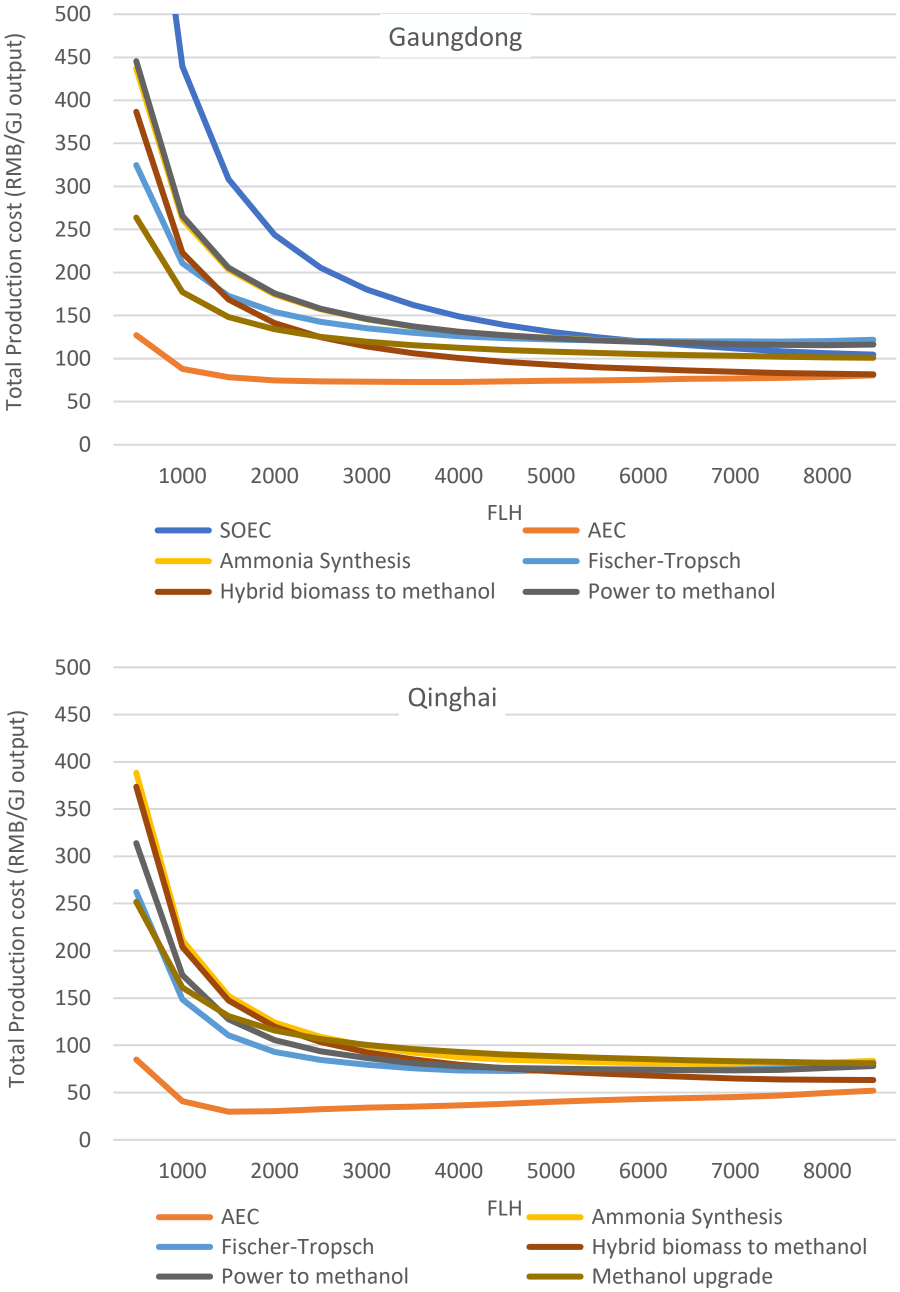
Table 6-8: FLHs for key PtX processes in specific years and over the 2030-2060 operation period

	Guangdong			Qinghai		
	2035	2060	Average	2035	2060	Average
AEC	8,532	5,839	**6,375**	8,476	6,898	**7,830**
SOEC	7,065	8,760	**8,552**	N/A	N/A	**N/A**
Ammonia Synthesis	7,512	7,175	**7,023**	7,408	6,802	**7,152**
Fischer-Tropsch	7,526	4,496	**5,897**	7,300	4,085	**5,381**
Power to methanol	7,615	6,592	**6,519**	8,164	6,997	**7,570**
Methanol upgrade	8,760	8,748	**8,749**	8,716	7,755	**8,216**
Hybrid biomass to methanol	8,760	8,760	**8,747**	8,760	8,363	**8,730**

The higher number of FLHs for some technologies may challenge the degree to which some PtX processes' electricity consumption can be counted on to provide flexibility as opposed to additional baseload electricity demand. However, Table 6-8 highlights the fact that some of the processes that are more sensitive to electricity prices will generally have lower FLHs relative to similar technologies that are less sensitive to electricity prices. This can be seen when comparing AEC to SOEC, or power to methanol with hybrid biomass to methanol, where the former in both cases requires more electricity per GJ of fuel output. The respective roles of CAPEX and electricity prices in the number of FLHs for a technology is further highlighted when looking at the development in FLHs for each technology over time in the two provinces. The number of FLHs decreases over time for the four technologies that rely nearly solely on electricity for their input energy (AEC, Fischer-Tropsch, power to methanol, and ammonia synthesis). This is because as the anticipated CAPEX values decrease over time, cost of electricity plays a growing role in the total cost of production. This trend is more significant in Guangdong where electricity prices are higher. Meanwhile, with its lower electricity prices, this trend of lower FLHs over time is less significant in Qinghai.

The need for high FLHs to keep cost down is further highlighted in Figure 6-13, which displays cost estimates for producing each of the fuels in 2050 as a function of the number of FLHs in Guangdong (top) and Qinghai (bottom).

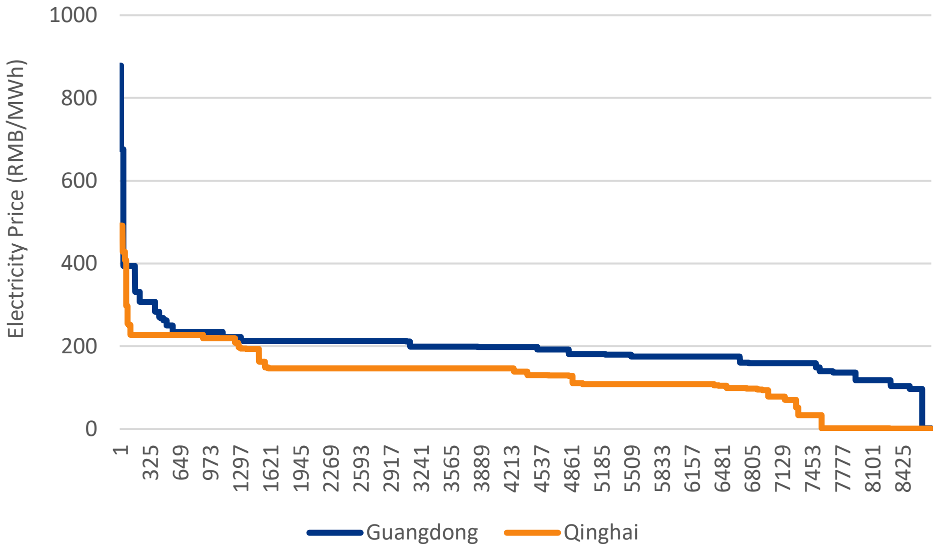
Figure 6-13: Estimated cost of production per GJ of output with increasing FLHs, for Guangdong (top) and Qinghai (bottom) in 2050



**For ease of viewing, note that the figure has been cut at 500 RMB/GJ, as SOEC greatly exceeds this value when under 1000 FLHs.*

Figure 6-13 highlights that for all technologies, the most significant cost reductions are realised around 4,000 to 5,000 FLHs, but that most technologies continue to realise cost reductions as the number of FLHs increases to roughly 7,500. The clear exception to this is AEC, which given the assumed development in technology costs and electricity prices in 2050, achieves its lowest production cost in the range of 3,500 FLHs in Guangdong, and 1,500 FLHs in Qinghai. The reason for this is highlighted in Figure 6-14, which displays an electricity price duration curve for the two provinces in 2050. In Qinghai, there are 1,500 hours with an electricity price below roughly 70 RMB/MWh. Meanwhile, with its higher electricity prices, the point at which it becomes more expensive to produce via AEC in Guangdong is around 3,500 FLHs which equates to an electricity price of roughly 180 RMB/MWh.

Figure 6-14: Electricity price duration curve for Guangdong and Qinghai in 2050[6]



Electricity prices contribute to hydrogen technology selection

As shown in the electricity price duration curve in Figure 6-14, the cost of electricity is also important when choosing which type of electrolysers to invest in. Based on the assumptions outlined in Table 6-2, the model can choose between AEC, PEM and SOEC. SOEC electrolysers use less electricity per hydrogen output than their AEC counterparts, and thus despite their considerably higher CAPEX and fixed O&M costs, the higher electricity prices in Guangdong result in SOEC being a viable option there from 2040 onwards. Meanwhile, Qinghai relies solely on AEC electrolysers for hydrogen production during the entire analysis period. Given the electrolyser input assumptions, AEC is a more cost-effective solution than PEM and as a result there is no PEM installed in the modelling

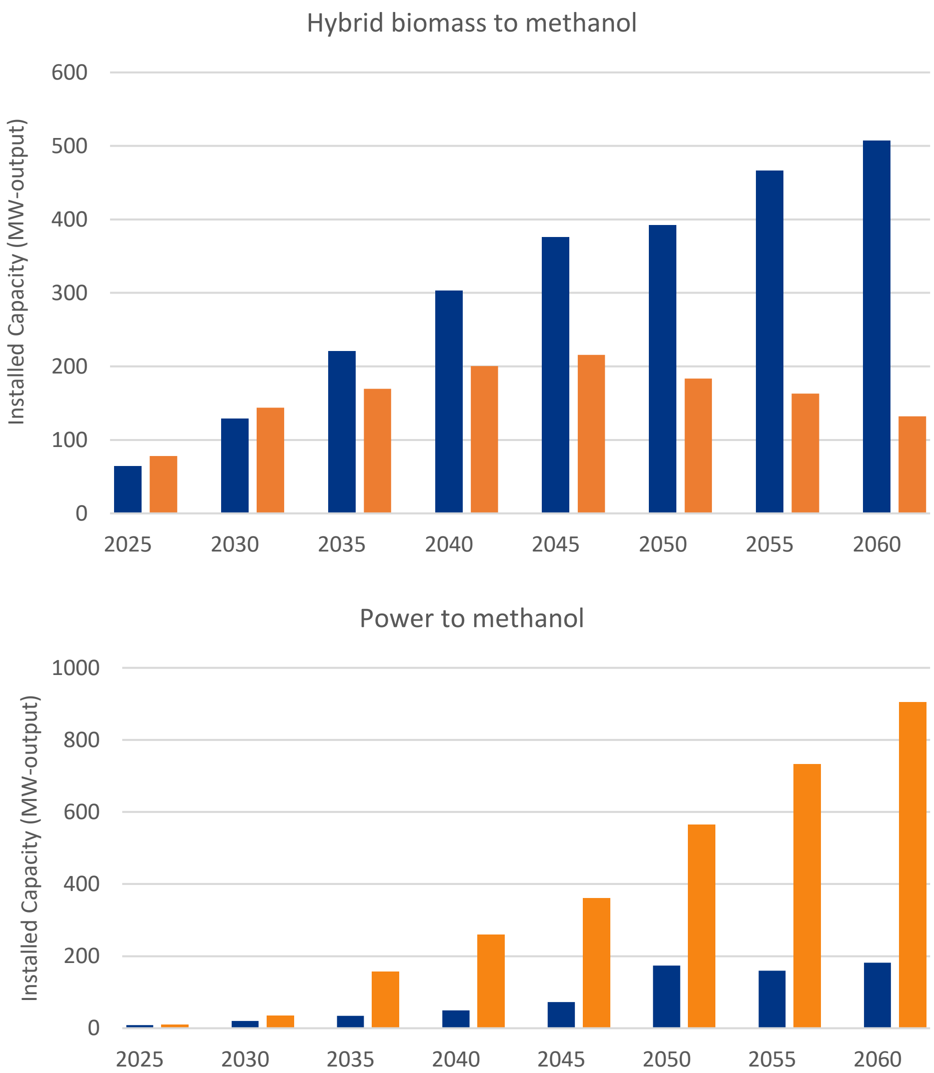
[6] Note that distribution and transmission charges are not considered explicitly. The PtX facilities are assumed to be quite large and connected at fairly high transmission levels.

analysis. In practice, however, it is likely that both PEM and other electrolyser technologies will also be used in the future.

CO_2 source: access to biomass as a source of CO_2

To both meet methanol demand and to provide input to the e-methanol upgrade, both provinces produce large quantities of methanol via one of two routes (see Figure 6-15 below).

Figure 6-15: Hybrid biomass to methanol (top graph) and power to methanol (bottom graph) production capacities for Guangdong (blue) and Qinghai (orange)



With its significant biomass resources, Guangdong produces large amounts of methanol via the biomass to methanol process. Conversely, in Qinghai, power to methanol is preferred as the biomass resources are much lower and there is a higher potential to provide additional low-cost renewable electricity supply. While both elements play a role in determining which methanol pathway is selected, it is the plentiful biomass resources that are deemed to be the dominating factor.

The selected methanol production route also determines how much captured CO_2 is required. In the biomass to methanol process, the CO_2 comes from biomass, while the power to methanol process requires captured CO_2. As a result, Qinghai requires much more captured CO_2 for methanol production.

Both Fischer-Tropsch and the power to methanol processes discussed above use carbon dioxide as an input, and as the demand for e-fuels increases during the analysis period, there is an increasing demand for captured CO_2. The utilisation of captured CO_2 in the two provinces is shown in Table 6-9.

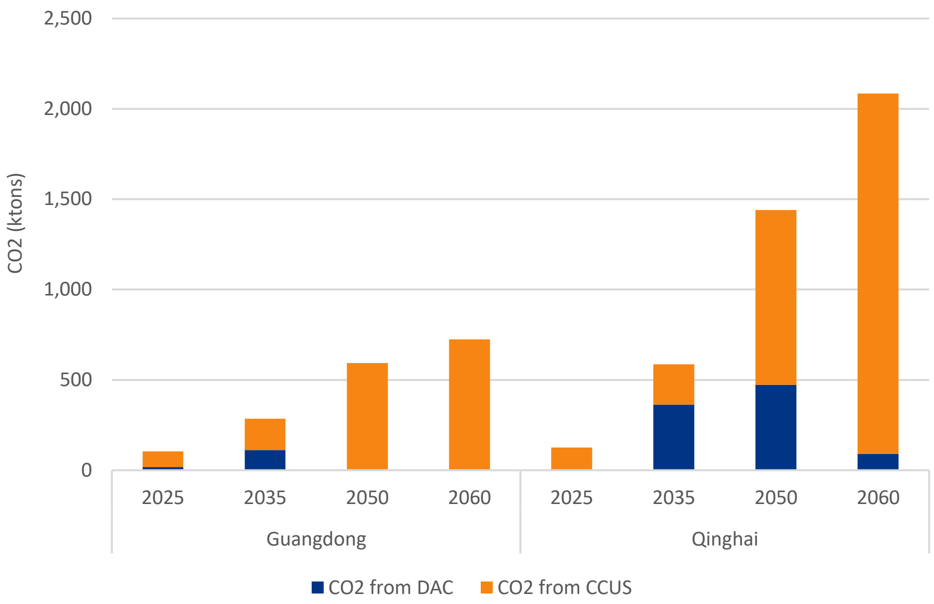
Table 6-9: Primary demand for CO2 (ktonnes) shown is for Fischer-Tropsch in Guangdong and for power to methanol in Qinghai

	Guangdong				Qinghai			
	2030	**2040**	**2050**	**2060**	**2030**	**2040**	**2050**	**2060**
Fischer-Tropsch	164	275	341	428	198	333	413	517
Power to Methanol	38	89	253	297	76	520	1028	1568
CO_2 (total)	***202***	***365***	***594***	***724***	***274***	***853***	***1440***	***2086***

CO_2 capture: reliance on DAC and CCUS

In the two provinces, CO_2 can be captured via two options. The first option is power generation technologies equipped with carbon capture. This includes coal, natural gas, straw, wood and MSW. Alternatively, CO_2 can be obtained from direct air capture (DAC) which is currently more expensive than capture from a power plant. Figure 6-16 highlights that in Guangdong, in the short term (i.e., 2025-2035), there is a need for DAC to supply the required CO_2 for PtX fuels, as carbon capture capacity in the power sector is still under development (see Figure 6-16). However, in Qinghai, where CCUS technologies are less prevalent and electricity prices are lower, there is a higher reliance on CO_2 from DAC throughout the entire period but the initial years. In the long-term, however, even here carbon capture becomes the largest source of CO_2. It should be noted that in this study PtX fuel demands are exogenous inputs, which means that the fuel demand values, and hence demand for CO_2 from carbon capture, may be higher in these scenarios in early years than is expecting to be the case in practise.

Figure 6-16: Dependence on direct air capture diminishes in the long term as more cost-effective carbon capture technology supplies the majority of CO2 demand towards 2060



As was alluded to previously, in Guangdong a large portion of methanol is produced via the biomass to methanol route, and the CO_2 for this methanol thus comes from biomass. This explains why Qinghai relies much more on captured CO_2.

Increase in PtX inputs due to increasing demand of e-fuels

The additional electricity consumption in Guangdong and Qinghai due to the introduction of PtX facilities in the provinces is rather substantial. In addition, several of the processes also utilise and/or produce heat.

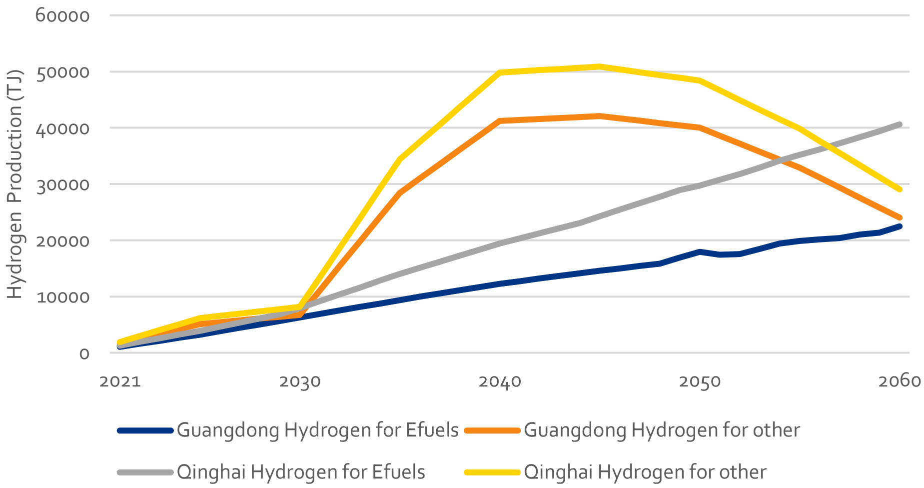
Table 6-10: Additional electricity demand as a result of PtX in Guangdong and Qinghai

	Guangdong				Qinghai			
	2030	2040	2050	2060	2030	2040	2050	2060
Electricity (TWh)	6	22	21	17	7	29	33	29

By 2050, the additional electricity needed for PtX in Guangdong and Qinghai grows to 21 and 33 TWh respectively. The development in electricity demand, as would be expected, is highly correlated to the demand for hydrogen, as electricity consumption from electrolysers comprises the vast majority of PtX electricity demand. Total hydrogen production caters to both hydrogen demand for the PtX processes, and for use in other sectors such as industry and transport. Driven by assumed improvements in electrolyser technologies and cost reductions, by 2045 hydrogen demand for these 'other' sectors increases to 42 PJ in Guangdong and 51 PJ in Qinghai. Towards 2060 this decreases to 24

PJ for Guangdong and 29 PJ for Qinghai, as the other hydrogen demand is strongly related to the steel production demand in the CESO model. Hydrogen production for other sectors and for PtX throughout the analysis period is displayed in Figure 6-17.

Figure 6-17: Increasing hydrogen production for e-fuels in contrast to the hydrogen demand for other sectors which peaks between 2040-2050 causing the electricity requirement to also peak around 2050



Effect on power sector from introduction of PtX facilities

Due to the increase in electricity required in the provinces to meet increasing demand from PtX, power generation capacity also increases. These changes in installed capacity are shown in the tables below for Guangdong and Qinghai respectively. The scenario without PtX uses the energy mix from the CETO Baseline scenario excluding PtX facilities.

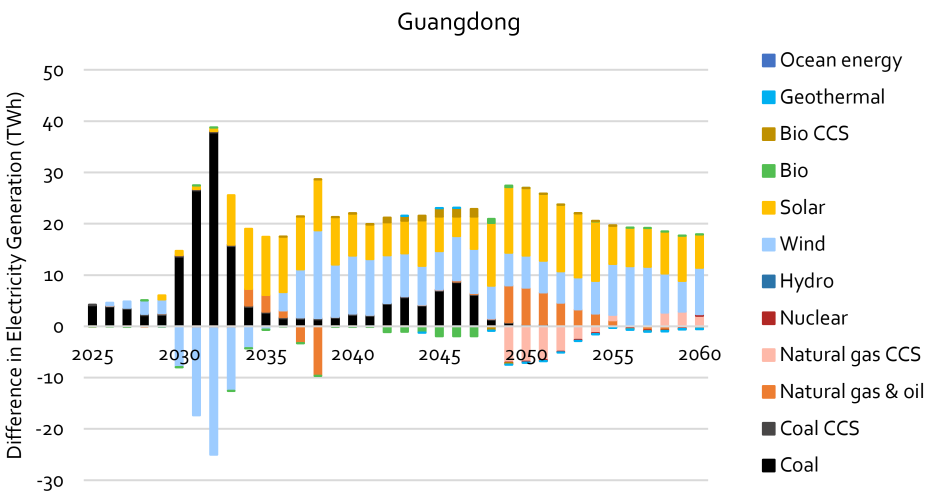
In Guangdong, solar and wind capacity in 2060 increases to 77 GW and 103 GW respectively, compared to 70 GW and 99 GW without PtX. This contributes to a 1% increase in the renewable share in the overall capacity mix.

Table 6-11: Comparison of installed capacities (GW) in Guangdong with and without PtX

Guangdong	Without PtX				PtX			
Year	2030	2040	2050	2060	2030	2040	2050	2060
Total Capacity (GW)	**174**	**209**	**227**	**223**	**173**	**224**	**244**	**233**
Coal	59	41	13	0	60	42	15	0
Coal CCS	0	0	0	0	0	0	0	0
Natural gas & oil	33	27	21	4	33	28	20	4
Natural gas CCS	0	0	15	15	0	0	14	15
Nuclear	18	20	20	20	18	20	20	20
Total RE Capacity (GW)	**64**	**121**	**158**	**183**	**62**	**133**	**175**	**194**
Hydro	8	8	8	8	8	8	8	8
Wind	42	98	97	99	39	102	99	103
Solar	11	11	48	70	12	20	62	77
Biomass	2	2	2	1	2	2	1	1
Biomass CCS	0	0	1	1	0	0	1	1
Geothermal	0	0	1	1	0	0	1	1
Ocean	0	1	2	2	0	1	2	2
Fossil fuels (%)	**53%**	**33%**	**21%**	**9%**	**54%**	**31%**	**20%**	**8%**
Non-fossil fuels (%)	**47%**	**67%**	**79%**	**91%**	**46%**	**69%**	**80%**	**92%**
Renewable (%)	**37%**	**58%**	**70%**	**82%**	**36%**	**59%**	**72%**	**83%**

While in the long term there is higher generation from solar and wind, this is not seen in the short term for Guangdong. On the contrary, around 2030 there is increased generation from coal and a reduced contribution from wind. One of the contributing factors is the lack of a hard CO_2-cap during this period, which allows for coal-based generation to increase. A supplementing factor is the need for continuous power supply required for the PtX capacity which operates at high full load hours thus making a baseload technology such as coal attractive. However, these factors change in the long term with a stricter CO_2-cap coupled with lower costs and improved efficiencies for PtX technologies. Hence, a policy initiative such as a CO_2-cap is important in the near term to ensure that PtX leads to emission reductions and not a rise in emissions.

Figure 6-18: Increasing electricity generated (TWh) in the long term from solar and wind in Guangdong with PtX as compared to without PtX from the Baseline scenario



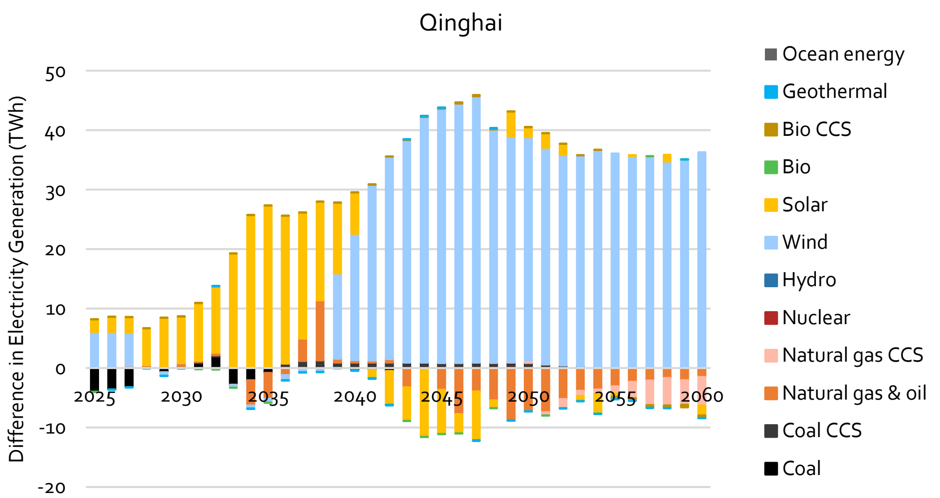
In Qinghai, by 2060 the introduction of PtX leads to an overall 15 GW increase in power generation capacity mainly consisting of additional wind capacity. However, the PtX driven electricity demand does not lead to a significant variation in the split between renewable and fossil-based capacity in Qinghai's energy fleet. This is as expected with the high renewable potential in the province.

Table 6-12: Comparison of installed capacities in Qinghai with and without PtX

Qinghai	Without PtX				PtX			
Year	2030	2040	2050	2060	2030	2040	2050	2060
Total Capacity (GW)	110	140	257	258	115	154	276	273
Coal	4	3	0	0	4	3	0	0
Coal CCS	0	0	0	0	0	0	0	0
Natural gas & oil	9	22	22	14	9	24	24	15
Natural gas CCS	0	0	0	5	0	0	0	4
Total RE Capacity (GW)	98	115	235	239	103	127	252	254
Hydro	23	23	23	23	23	23	23	23
Wind	17	12	32	32	17	20	48	48
Solar	58	80	181	184	63	84	181	183
Fossil fuels (%)	11%	18%	9%	7%	11%	18%	9%	7%
Non-fossil fuels (%)	89%	82%	91%	93%	89%	82%	91%	93%
Renewable (%)	89%	82%	91%	93%	89%	82%	91%	93%

The variation in the Qinghai's capacity build out is also reflected in the generation profile with power from solar being the initial source to meet the increased demand due to PtX, and wind taking over in the later years.

Figure 6-19: Introduction of PtX production in Qinghai province leads to an increased generation initially from solar and then wind in the later years, as compared to without PtX.



Changes in net CO2 emissions due to introduction of PtX facilities

The change in net CO_2 emissions for China due to the production of PtX fuels are comprised of three parts. Firstly, they include CO_2 emissions from the power and heat sector attributed to the change in the power system due to introduction of PtX facilities. These changes are primarily driven by the additional electricity required to produce hydrogen, as well as the need to capture CO_2 for use in some PtX fuels. Secondly, they include CO_2 utilised in the production of PtX fuels containing carbon, which is assumed to be released again upon consumption. Lastly, they include CO_2 emissions associated with traditional fuels that otherwise would have been produced and utilised but are now replaced by PtX fuels. It is assumed that these fuels would predominantly be dependent on fossil fuels for their production. The CO_2 content as well as the upstream emissions associated with these 'reference' fuels are displayed in Table 6-13.

Table 6-13: Energy content and assumed reference CO_2 emissions for traditional production methods of selected fuels analysed

	Methanol*	Jet fuel	Gasoline	LPG	Diesel	Naphtha	Ammonia	Hydrogen**
Energy content (GJ/t) (LHV)	19.9	43.5	43.8	46.1	42.7	44.9	18.6	120.0
CO_2 Content (kg CO_2/GJ)	68.8	70.0	73.0	65.0	74.0	73.3	-	-
Upstream emissions (kg CO_2/GJ)	149.3	10.5	8.2	9.8	14.4	11.0	150.5	75.0
Total CO_2 emissions (kg CO_2/GJ)	**218.1**	**80.5**	**81.2**	**74.8**	**88.4**	**84.3**	**150.5**	**75.0**

** From coal*

*** From fossil fuels*

The table highlights the large differences in the upstream emissions from the various fuels, which will largely depend on how and where these fuels are produced. The large variations in the traditional fuels total CO_2 intensities suggest that from a CO_2 emissions reductions perspective, it could be beneficial to prioritise which PtX fuels to produce.

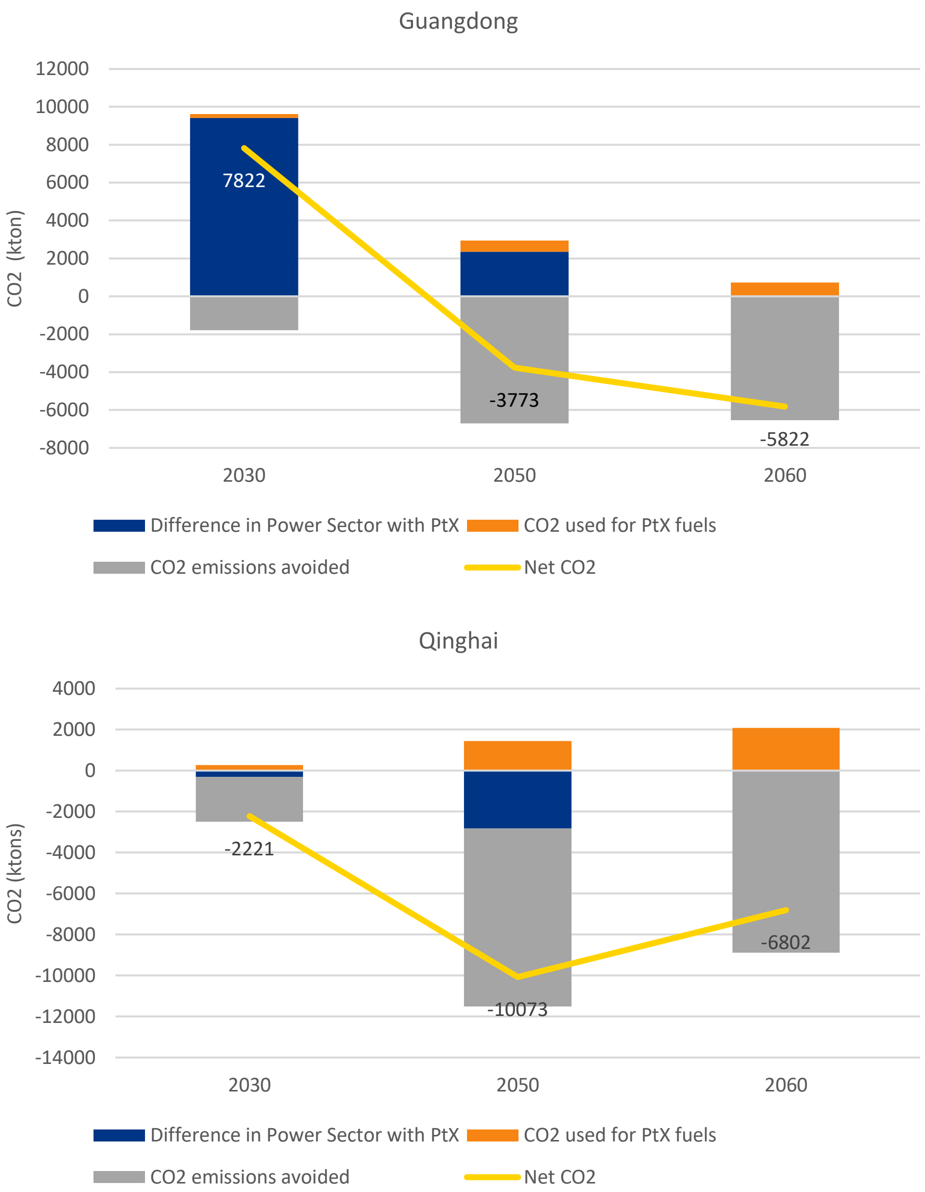
Figure 6-20 below displays the change in net CO_2 emissions due to the production of PtX fuels for selected years in the two provinces. For the power and heat sector, the primary drivers for the reduction in CO_2 emissions are the CO_2 target constraints. However, the PtX demand has also driven a significant increase in the use of renewable energy.

In the initial years, i.e. 2030, the increase in demand for baseload electricity in Guangdong for PtX fuels is largely supplied by coal, and therefore the additional CO_2 emissions from the power sector (the blue portion in Figure 6-20), greatly exceed the CO_2 emissions avoided via the PtX fuels (the grey portion). This is due to the high losses in the conversion processes of PtX (see Table 6-3), which means that not only is using a fossil fuel directly much cheaper, it also emits less than using a fossil as input to a PtX process.

However, by 2050, as PtX production has increased significantly, the additional CO_2 emissions from the power sector (which is now largely decarbonised) are more than offset by the avoided emissions. Lastly, by 2060, the additional electricity generated for PtX does not generate any CO_2 emissions, so the net emission savings grow to 5.8 MT.

Meanwhile, in Qinghai, the introduction of PtX results in CO_2 emission reductions from the very beginning, as the additional electricity demand is supplied by solar and wind resources. This is particularly the case in 2050, as natural gas-based electricity production is replaced with wind power in a situation with PtX production. By 2060 the power sector is largely decarbonised in both scenarios so the emission reductions are solely due to the CO_2 emissions avoided via the PtX fuels.

Figure 6-20: Reduction in carbon emissions in Guangdong (top) and Qinghai (bottom) with PtX relative to baseline without PtX



In comparing the two provinces, a key takeaway from a CO_2 emission reduction perspective is that largescale PtX production should not take place in a province until it can be assured that the additional electricity demand required can be met by CO_2 free sources. Hence, initial PtX development should be prioritised in provinces such as Qinghai and then be implemented in provinces such as Guangdong at a later point.

When compared to a system without PtX, the reduction in CO_2 emissions for the two provinces in the period of 2030-2060 is a combined 284 mega tonnes. These reductions highlight the importance of transitioning to a more renewable-based power system not only to meet future conventional demand, but also to produce e-fuels necessary to decarbonise the industry and transport sectors. Hence, if PtX is to play a significant role in reducing emissions, the RE capacity needs to be rapidly increased to ensure sufficient low-carbon electricity as input.

Estimated CO2 emission abatement cost

For three 10-year periods, estimated CO_2 emission abatement costs were calculated by comparing the estimated reductions associated with PtX as described above, with the additional costs incurred in the power and heat sector. As the production cost of the fossil fuels that the PtX fuels replace were *not* included, the CO_2 abatement costs in the table below should be seen as an upper range. Nonetheless, initial analysis suggests a CO_2 abatement cost associated with producing and utilising PtX fuels rather than their fossil fuel counterparts in the range approaching 1,500 RMB/tonne for the period 2030-2060.

Table 6-14: Estimated CO2 abatement cost (RMB/tonne)

	2030-2039	2040-2049	2050-2060
Guangdong	2,857	2,346	1,727
Qinghai	1,548	1,341	1,359
Weighted average	1,457	1,633	1,481

7 Carbon pricing

7.1 Key messages

Adding a cost for CO_2 emission (Carbon pricing) is an important policy instrument in the overall climate policy framework. China launched national carbon emissions trading system (ETS) in 2021 after a decade in the making. This market-based mechanism is supposed to provide incentives for low-carbon technology and drive emissions reduction, contributing to China's decarbonization pathway to 2060. In addition to emissions trading system, other types of carbon pricing schemes such as carbon tax could similarly be introduced and play its role in driving the transformation.

The effectiveness of carbon pricing lies much in the design of the policy tool. Similar to the EU-ETS and many other emissions trading schemes during their early stages, the current setup of the national ETS is not sufficient and stringent enough for fulfilling China's carbon neutrality goals, and the ETS design must be improved to ensure the right incentives for the stakeholders. The improvements could be carried out in the following steps:

1) The national ETS shall set its reduction target and total allowance allocation in line with China's overall climate target, switching from intensity-based target to a cap-and-trade system with a fixed cap for the total number of allowances allocated, which is very much expectable according to the most recent policy movement of shifting from energy intensity and carbon intensity control to total CO_2 emissions and carbon intensity control as disclosed from the 2021 annual economic work conference of the CPC Central Committee. Furthermore, it is important to have a mechanism to reduce the total amount of allowances over time to ensure a sufficiently high price of allowances. It could also be considered to introduce a (rising) floor price to ensure a long-term stable investment climate.
2) Auctioning of allowances shall be gradually introduced to make enterprises more aware of carbon costs. The current setup with 100% free allowances based on benchmarks could promote more new coal-fired power plants being built instead of promoting zero-carbon emission technologies like wind and solar power. Thus, gradual introduction of auctioning allowances would incentivize power enterprises to ramp up investments in renewables in order to reduce carbon costs. Auctioning can also bring additional revenues for the government, which can be used for supporting low-carbon technologies.
3) As carbon pricing provides incentives for renewables investments, it is valuable to ensure the consistency and synergy between carbon pricing and RE support policies.

7.2 Carbon pricing internalises the costs of emissions

Carbon pricing is a primary policy approach to address climate change since it forces polluters to pay for the negative externality from their carbon emissions. There are explicit carbon pricing instruments such as carbon price in carbon market, carbon tax etc where emitters must pay for per unit of emission. In contrast, there are implicit carbon pricing instruments such as emissions standards or strict regulatory emissions target, which will then form a shadow carbon price.

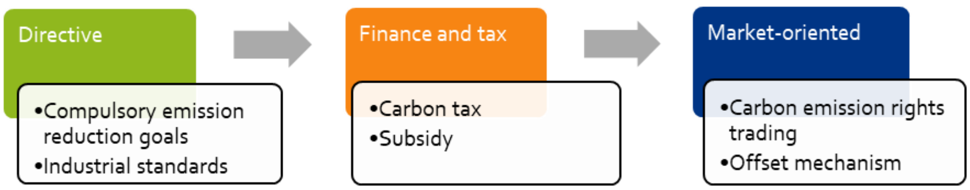
Carbon market uses the uniform price signal to optimize resources and incentivize emission reduction efforts, achieving cost-effectiveness and realize the least-cost abatement. Cap and trade is the standard setup of carbon market, emissions trading system (ETS), in which the government hands out certain amount of allowances and emitters need to surrender enough allowances to cover its emissions. Otherwise the emitters will face penalty or need to carry out abatement measures. It often sets certain threshold for inclusion into the system, covering mainly energy-intensive enterprises such as thermal power generators, heavy industry etc.

Thus, incentivized by the implementation of ETS, enterprises will treat allowances as cost elements in its production and internalize the carbon costs. Higher allowance prices will then send stronger signal for the emitter to cut emissions and drive competitiveness of low carbon technology such as renewables, hydrogen etc. According to the World Bank, there are 61 carbon pricing initiatives implemented/scheduled globally as of 2020, covering 12 Gt CO2e (22% of global GHG emissions).

7.3 China launched national ETS in 2021

China has been relying on regulatory measures and stringent targets in achieving energy savings and emissions intensity goals. Subsidies have also been one of the key low-carbon policies. The construction of national carbon market indicates gradual transition from pure regulatory measures to more hybrid approach consisting of both market-based and regulatory measures. This transition will help to counterbalance the pressure from rising fiscal subsidies and adverse impacts of direct control policies.

Figure 7-1 Significance of developing carbon trading system

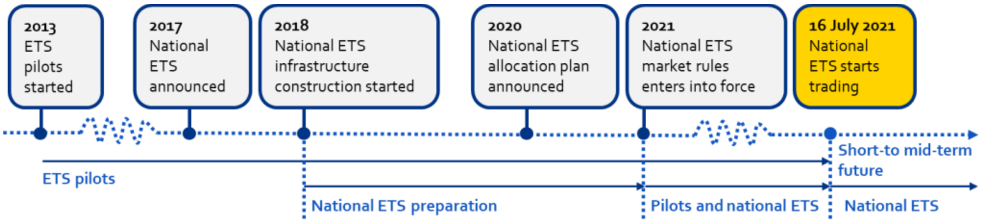


Source: Ministry of Ecology and Environment (MEE)

Since 2013, China has established 7 pilot ETS in order to gather experiences and lay ground for the eventual construction of a national carbon market. The pilots have covered over 3000 enterprises covering over 20 sectors including power generation, steel, cement etc. A total of 480 million tonnes of allowances have traded in the pilots as of June 2020, with total traded value of RMB 11.4 billion and weighted average of allowance price at RMB 40/t.

In January 2021, Ministry of Ecology and Environment announced the launch of first compliance period in national ETS. It only covers power sector, and a total of 2225 enterprises are included whose total yearly emissions are around 4.5 Gt in 2020. These enterprises need to surrender allowances for their emissions in 2019 and 2020 by 31 December 2021. The national ETS management rules (trial) entered into force on 1 February and allowance trading kicked off on 16 July 2021. The national ETS is expected to gradually expand to more sectors during the 14 FYP, eventually covering 8 industry sectors, covering 70% of China's CO2 emissions.

Figure 7-2: China national ETS timeline



7.4 National ETS shall switch from intensity-based target to absolute reduction target

At the start, China national ETS adopts an intensity-based target, in contrast to the absolute emissions target in other Cap and trade schemes. This approach is chosen for the purpose of being consistent with China's climate target in the 14 FYP, i.e. the GDP intensity goal. Thermal power plants are given certain number of allowances based on a predetermined benchmark for its fuel type and capacity category (emissions intensity, in ton CO2/MWh). Thus, aging and inefficient thermal plants is expecting to be punished if their emission intensity is above the benchmark since they need to buy allowances for compliance. On the contrary, more efficient thermal plants will have surplus allowances as subsidies since they can sell in the carbon market and get revenue.

There is a limitation of intensity-based target. Even though it can improve the overall efficiency of the thermal power fleet (mainly coal), it also provides incentives for building new and more efficient plants whose emission intensity will below the benchmark. Moreover, the ETS emissions will rise as long as total output (thermal power generation) increases. With China set to peak emissions before 2030, it is necessary to bring the ETS target in line with the overall emissions target. This implies that national ETS shall quickly move to absolute emissions reduction target in order to drive down emissions in the ETS-covered sectors, fulfilling the 2030 carbon peak goal. Government could define the contribution of the ETS into the overall climate target.

In addition to the switching from intensity-based target, national ETS shall also gradually introduce auctioning of allowances, and reduce the free allocation of allowances. The revenues from auctioned allowances could be used as funding for investments and innovation in low-carbon technology. If free allowances will continue in the future, all types of power producers, including wind and solar power producers, should have allowances based on the power production from the plants.

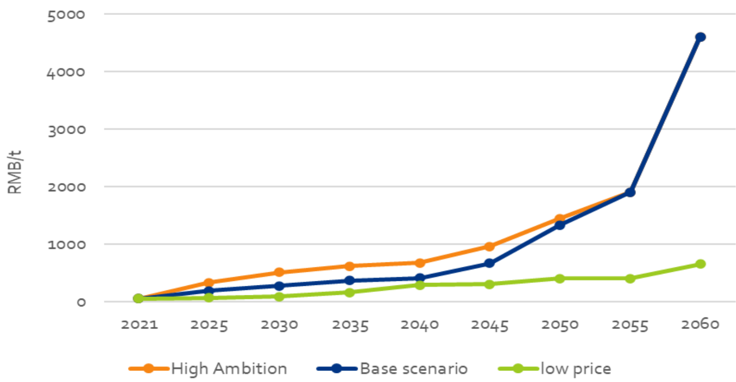
7.5 Carbon price outlook scenarios

Allowance price shall reflect the abatement costs at different stages of emission reduction efforts, on a rising pathway to mirror the ramping up of required reduction efforts. In the early stage, ETS price mainly reflects the costs of low-hang fruits of abatement measures such as improving fuel quality, retrofit equipment, optimize production process etc. Further onwards, the ETS price will rise to reflect more costly abatement, such as the differences between renewables and fossil fuel costs or the costs of abatement technologies, i.e. the Green Premium. Towards 2050 when the power sector has fully decarbonized and carbon removals such as CCUS and BECCs might be essential to achieve net-zero emissions by 2060, ETS price will surge sharply to the level of these costly abatement measures.

3 Carbon price scenarios are depicted below.

- **Low price scenario:** ETS is sidelined in policy instruments. The market design is very slack with very generous benchmarks for power and industrial enterprises who will have sufficient allowances for compliance. Trading activities remain low and allowance price rises from currently 45 RMB/t to 85 RMB/t in 2030, 280 RMB/t in 2040 and 400 RMB/t in 2050.
- **Base scenario:** ETS is strengthened and becomes an important tool in driving renewables deployment and abatement technology. Absolute cap will be aligned to China's 2030 carbon peak goal and carbon neutrality pathway, and companies will get less allowances year on year. Auctioning will be gradually introduced and the share of free allocation declines. Carbon trading activities become active and liquid. ETS allowance price will rise from currently 45 RMB/t to 270 RMB/t in 2030, 407 RMB/t in 2040 and 1327 RMB/t in 2050.
- **High Ambition:** ETS is strengthened and become a cornerstone of China's climate policy, being a core instrument boosting investments in renewables and abatement technology. Absolute cap will be introduced and auctioning share gradually increase combined with lower free allocation. Global ETS linkage will progress faster and China ETS price will move towards synergy with EU ETS. ETS allowance price will rise more rapidly from currently 45 RMB/t to 506 RMB/t in 2030, 672 RMB/t in 2040 and 1444 RMB/t in 2050.

Figure 7-3: China carbon price scenarios



7.6 Carbon tax in certain sectors

Both carbon market and carbon tax are major carbon pricing instruments. The key difference is that carbon tax is a price-type policy and regulators determine the tax rate, i.e. the carbon costs. Thus the amount of emissions reduction is unknown. In comparison, carbon market is a quantity-type policy. The total emissions reduction could be predetermined in the carbon market, and the carbon price is discovered via trading of market participants. Uncertainties of abatement costs and benefits affects the choice of price vs quantity policy.

Typically, carbon tax is viewed as having several advantages, clear price signal, carrying lower regulatory costs, easily implemented and simpler policy design. However, the implementation of carbon tax could face stronger political obstacles. Carbon market on the other hand could also be easily accepted by participants if certain number of free allowances are guaranteed, despite the complexity of setting up ETS. In addition, the ETS price could also be used as reference for the level of carbon tax. This can ensure synergy between the two carbon pricing instruments and send uniform signal to the society.

A hybrid approach could be established, with carbon market covering energy intensive facilities and carbon tax applied to smaller emitters such as buildings and transport sectors. Both pricing instrument can then generate revenues for the government, which can be used in the investments needed for green transformation.

A starting point could be to revise existing tax items such as coal resources tax or oil consumption tax, imposing tax on carbon content of fossil fuel consumed. This can gradually be transformed to a standalone carbon tax, supplementing the existing environment tax framework. Rising costs of emissions will then put pressure on sectors and production processes that are emission-intensive, incentivizing the producers to switch to low-carbon options.

The introduction of the carbon tax scheme shall take place in phases and be gradual, to not to put excess burden on enterprises and leave sufficient time for them to adjust technology deployment. It is also important to ensure carbon price and carbon tax do not drive up Inflation significantly, when producers tend to pass through carbon costs to final products and consumers. The usage of revenues from carbon tax or auctioning of ETS allowances also need to be specified carefully to ensure these are invested in low-carbon technology and emission reduction.

7.7 Carbon pricing and other RE support

The role of carbon pricing needs to be in synergy with other climate and energy policy too, together contributing to the overall climate goal. Carbon market could not only incentive fossil-power producers to improve efficiency, but also provide incentives for investments in renewables and low-carbon technologies.

The Clean Development Mechanism has provided support for the development of renewables projects in China, during the period between 2005 and 2012. Around 3800 CDM projects are registered in China, 80% of which are solar and wind projects. By then, the offsets (CER) from CDM projects can also be used for compliance in European carbon market, thus generating revenues for project developers in China.

In 2012, China launched the CCER scheme, China Certified Emission Reduction. It is quite similar to CDM, and covers project types such as renewables (solar, wind and hydro), forestry, methane utilization, waste treatment etc. Enterprises can purchase CCER, either for its compliance obligation in the seven pilot ETS and for voluntary offsetting. Average CCER traded price was 30 RMB/t in 2020. In the new national carbon market launched in 2021, power enterprises are allowed to use up to 5% CCER for its compliance obligation in year 2019 and 2020. This is for the purpose of reducing the compliance costs of enterprises in the ETS.

The renewables consumption quota and green certificates schemes will advance further and can work alongside the ETS. This means that renewables projects can be excluded from the CCER scheme in the future. Green certificate exhibits the green attribute of renewables power and its revenue can support RE project developers. The unsubsidized Green certificate has been introduced since May 2021, and price held at 50 RMB/MWh. This is in fact already higher than current CCER price based on the assumption of 0.6 tonne CO_2/MWh emission factor, thus higher revenue for the RE project developers.

The ETS will interact with other climate and energy policies. More rapid progress in power market liberalization will facilitate the strengthening of carbon price signal, incentivizing the deployment of renewables. Ambitious RE target will lead to faster coal phase down and cut emissions faster, reducing ETS allowance demand and put pressure on prices. So, this in turn requires robust market adjustment mechanism to ensure stability in the carbon market, which can be allowance supply side control or carbon price ceiling and floor mechanism.

8 Status and Prospects of CCUS Development in China

8.1 Key messages

As the world's largest energy consumer and carbon emitter, China has long recognized carbon capture, utilization and storage's (CCUS) potential to allow the country continuously utilize fossil fuel especially coal while simultaneously achieving deep carbon emissions reductions. In the past decade, the Chinese central government released at least 26 CCUS-related policies, focusing on both technology research and development (R&D) and industrial demonstrations. Against the backdrop of China's climate pledge of peaking carbon emissions before 2030 and achieving carbon neutrality before 2060, CCUS policies in China become increasingly proactive and supportive. Because of CCUS development's unique strengths, weaknesses, opportunities, and threats summarized in this chapter, the overall mitigation impact of CCUS in China has been limited so far, despite the relatively mature technology in carbon capture and breakthroughs in geological utilization. Between 2007 and 2019, China reached a cumulative carbon dioxide (CO_2) storage volume of 2 million tons (Mt), in contrast to its national carbon emissions at 9.8 billion tCO_2 in 2019.

Given the nature of the landmark "carbon peaking and carbon neutrality" climate pledge, China's CCUS strategy should also be formulated in a phased approach. More specifically, before 2030, China should aim:

- To further improve quality of energy and emissions statistical reporting: As reliable statistics are the foundation of sound energy and climate decision-making, China has already made significant efforts to improve quality of its basic energy statistics in the past. To ensure a smooth regulatory and market regime in support of CCUS development in the next decade, it is important for China to further improve quality of its energy and emissions statistical reporting;
- To establish supportive and comprehensive CCUS regulations and standards; To promote CCUS R&D and commercialization in China, there are many regulatory deficiencies to be resolved, including the lack of an enforceable legal framework, insufficient information for the operationalization of projects, weak market stimulus, and a lack of financial subsidies and complicated approval process. In addition, CCUS-related standards should be improved to cover the entire industrial value chain from site selection to emissions abatement verification;
- To eliminate all fossil fuel subsidies to stimulate market penetration of net-zero emissions technologies including CCUS in the domestic front; and to proactively work with the EU and other like-minded countries with net-zero emission targets to explore a multilateral instead of unilateral solution for carbon leakage protection in the international front.

- After 2030, China should aim to ensure a fair and transparent regulatory framework to allow CCUS compete with other net-zero technologies on an equal footing basis. In addition, China should also strive:
- To continuously learn CCUS-related experience and lessons from regions with high carbon prices especially EU countries through enhanced international cooperation; and
- To promote deployment of large-scale CCU projects by government imposed Five-year Plan (FYP) targets or financial subsidies, while large-scale geological storage of captured CO2 emissions should serve as China's "last resort" backup option to achieve carbon neutrality once all other viable alternatives are exhausted before 2060.

8.2 Overview of CCUS development in China

Carbon capture, utilization and storage (CCUS), also referred to as carbon capture, utilization and sequestration, is a climate mitigation process that captures CO_2 emissions from large point sources such as power plants and industrial facilities, then either reuses it or transport it to a storage location for the purpose of long-term isolation from the atmosphere. Similar as the rest of the world, potential of CCUS development in China has been largely untapped: its effectiveness to reduce carbon emissions is well recognized by key stakeholders, but deployment beyond small-scale pilot projects has been slow, leading to limited impacts on national carbon emissions so far. From 2007 to 2019, China reached a cumulative CO_2 storage volume of 2 million tons (Mt), averaging 0.16 $MtCO_2$/annum, while China's national carbon emissions were 9.8 billion tCO_2 in 2019.[70]

As a commercially immature, relatively expensive but effective climate mitigation technology, CCUS could, in theory, possess great potential to become one of the key pillars to decarbonize the Chinese economy, along with energy conservation, net-zero emissions-oriented electrification, bioenergy, green hydrogen, and enhancement of biological sinks including afforestation and reforestation. Following China's landmark climate pledge of peaking national carbon emissions before 2030 and achieving carbon neutrality before 2060, CCUS development gained additional traction, making it rather imperative to better understand its role in China's clean energy transition.

CCUS technology development in China

During the past decade, China has made rapid progress in developing CCUS technologies. As a result, carbon capture is relatively mature, with several major breakthroughs made in the field of geological utilization and storage.[71] More specifically, among mainstream carbon capture technologies, post-combustion is the most mature one in China compared with pre-combustion and oxy-fuel. Pilot pre-combustion CCUS projects in China include integrated gasification combined cycle (IGCC) and industrial separation, while oxy-fuel combustion is still in the R&D phase.[72]

Carbon capture has been demonstrated in six Chinese industries so far, with coal chemical as the most preferred industry for experiment, followed by thermal power, natural gas processing, methanol manufacturing, cement, and fertilizer plants. Compared to the United States, where CCUS is also rapidly taking shape, carbon capture is not currently deployed in petroleum refining, blue hydrogen, and ethanol production in China.[73]

Geological utilization and storage projects in China mainly focus on enhanced oil recovery (CO_2-EOR), which has already entered the initial stage of commercialization.[74] CO_2-EOR is an appealing technology option, as elevated oil output helps offset part of CCUS-related costs, with specific ratio depending on international oil prices. Other technologies, such as enhanced coal bed methane recovery (CO_2-ECBM) and saline aquifer storage, are still in the pilot project phase.[75]

Chemical and biological utilization converts CO_2 emissions into fuels, chemicals, and fertilizers. In 2019, chemical and biological utilization projects consumed about 0.85 $MtCO_2$, while geological utilization and storage projects stored about 1 $MtCO_2$.[76]

Mapping CCUS Projects in China

By the end of 2019, there were 18 operational carbon capture projects in China, that are responsible for capturing 1.7 $MtCO_2$, followed with 12 geological utilization projects, 8 chemical utilization ones, and 4 biological utilization ones. In addition, 10 of the above ones are integrated demonstration projects.[77] As of July 2021, around 40 CCUS demonstration projects are either in operation or under construction across the country, with an aggregate capture capacity at 3 $MtCO_2$/annum.[78]

China's CCUS projects spread across 19 provinces, capturing carbon emissions from diverse industrial sources. Most of carbon capture projects are sited in either northern or eastern China. In comparison, CO2-EOR projects are primarily located in major oil and gas basins in northern China, more specifically, in Shengli Oilfield and Zhongyuan Oilfied of China Petrochemical Corporation (Sinopec), as well as Daqing Oilfield, Jilin Oilfield, Xinjiang Oilfield, and Changqing Oilfield of China National Petroleum Corporation (CNPC).[79]

Notable CCUS Projects in China

The IEA defines large scale CCUS projects as those involving the capture of at least 0.8 $MtCO_2$/annum for a coal-fired power plant or 0.4 $MtCO_2$/annum for other emission-intensive industrial facilities (including natural gas-based power generation).[80] While China has the engineering capability to capture, utilize, and store CO_2 at scale, the majority of existing CCUS projects are still of small-scale. There are three large-scale CCUS projects in China as of September 2021: two in operation and one under construction, contained in 21 large-scale CCUS projects in operation globally.[81]

Operational since 2008, CNPC's Jilin Oilfield CO_2-EOR project is one of the earliest large CCUS demonstration projects and the first integrated one in China. The project has a capture capacity of 0.6 $MtCO_2$/annum from a natural gas processing plant via pipeline for the purpose of EOR, with an annual storage capacity of 0.3 $MtCO_2$ and oil producing capacity of 0.12 Mt. As of 2019, 1.45 $MtCO_2$ has been injected.[82]

Operational since 2016, the Yanchang Integrated CCS Demonstration project has a capture capacity of 0.3 MtCO2/annum from the coal chemical industry for the purpose of CO2 flooding demonstration.[83] The large-scale project under construction is the Sinopec Qilu Project in Shandong province, which has a long-term capture capacity of 1 $MtCO_2$/annum and is expected to be operational by the end of 2021.[84]

Other notable projects include but not necessarily limited to:[85]

1. Operational since 2005, Sinopec's EOR demonstration in the East China Oilfield locates in Dongtai, Jiangsu, has a capture capacity of 160 ktCO2/annum for the purpose of EOR. The cumulative CO2 capture of this project has reached 700 kt so far;
2. Operational since 2009, Huaneng Group's Shanghai Shidongkou CCS demonstration project has a post-combustion capture capacity of 120 ktCO2/annum;
3. Operational since 2011, Shenhua Group's Ordos CCS demonstration project in Inner Mongolia. Completed in 2011, it is the first coal-based integrated CCS project in China, with CO_2 sourced from Shenhua's direct coal liquefaction plant in Ordos. Four rounds of injection experiments were performed periodically from 2011 to 2014 with a cumulative injection of about 0.3 $MtCO_2$.[86]

In August 2021, CNOOC launched China's first offshore CCS project in South China sea. The project is expected to have a storage capacity of more than 1.46 $MtCO_2$ and is designed to reinject as much as 0.3 $MtCO_2$/annum into the seabed reservoirs.[87]

China is actively preparing for a full-process CCUS industrial cluster.[88] According to an analysis by IHS Markit, China could add eight large-scale CCUS projects and more than double its CCUS capacity by 2025 if all announced projects are funded.[89]

CCUS Policies in China

In the past decade, China has become increasingly proactive in terms of regulatory support for CCUS development and deployment. At the national level, there are at least 26 CCUS-related policies as of November 2019.[90] Policy measures focus on both technology R&D and industrial demonstrations.[91]

Since the 12th FYP period (2011–2015), CCUS has been included in China's carbon mitigation strategies.[92] In September 2011, the 12th FYP of Land and Resources was issued by the former Ministry of Land and Resources (now MNR) and the MOST. The plan proposed to develop technological demonstration project of geological carbon storage, as well as to explore artificial carbon sequestration technology.[93]

In December 2012, the MIIT, the NDRC, the MOST, and the MOF jointly issued the Industrial Action Plan of Climate Change in the Industry (2012–2020). The Action Plan called for developing integrated CCUS demonstration projects and CO_2 utilization technology in the chemical, cement, and steel industries.[94]

In February 2013, the 12th FYP for Science and Technology Development was released by the MOST. The Plan identified the technical bottlenecks around CCUS and proposed to construct full-process CCUS demonstration projects. The Plan also emphasized the importance of promoting basic research, technology R&D, and integrated demonstration in an orderly manner.[95]

Two notices on CCUS development were issued subsequently in 2013, which are: the Notice on the Promotion of CCUS Pilot Demonstration by the NDRC and the Notice on Strengthening Environmental Protection Work of CCUS by the former Ministry of Environmental Protection (now MEE).[96]

In September 2014, the National Climate Change Plan (2014–2020) was issued by the State Council, which defined CCUS as a key breakthrough technology.[97] The Plan not only called for deploying carbon capture projects in various industrial sectors, but also asked for demonstration and experiment of new technologies such as oil displacement and CO_2 reutilization.[98]

In April 2015, the Action Plan on Clean and High-efficiency Use of Coal (2015–2020) was introduced by the NEA. The Plan encouraged cooperation between coal chemical enterprises and oil companies to develop demonstration projects in EOR and geological storage, as well as to accumulate experience for large-scale demonstration projects.[99]

In June 2015, China submitted the Enhanced Action on Climate Change: China's Intended Nationally Determined Contribution (INDC) to the Intergovernmental Panel on Climate Change. According to the document, China will strengthen R&D and commercial demonstration of CCUS and promote the technology of enhanced oil recovery and coal-bed methane recovery.[100]

During the 13th FYP (2016–2020) period, multiple national special plans highlighted the importance of promoting CCUS technological R&D and establishing large-scale CCUS projects.

Published in October 2016 by the State Council, the 13th FYP for National Science and Technology Innovation highlighted the importance of post-combustion capture in achieving $MtCO_2$ level large-scale demonstration.[101]

In May 2019, the MOST and the Administrative Center for China's Agenda 21 (ACCA21) jointly issued the updated Roadmap for Development of CCUS Technology in China. The roadmap set the goals for reducing the cost and energy consumption of CO2 capture by 10% to 15% in 2030 and by 40% to 50% by 2040. The roadmap foresees extensive CCUS deployment by 2050, supported by multiple CCUS hubs across the country.[102]

The 14th FYP, released in March 2021, has imposed higher pressure for heavy industry decarbonization. The Plan highlighted the role of CCUS in resource conservation and utilization and called for implementing major near-zero emission CCUS demonstration projects.[103]

8.3 A Simplified SWOT Analysis of CCUS Development in China

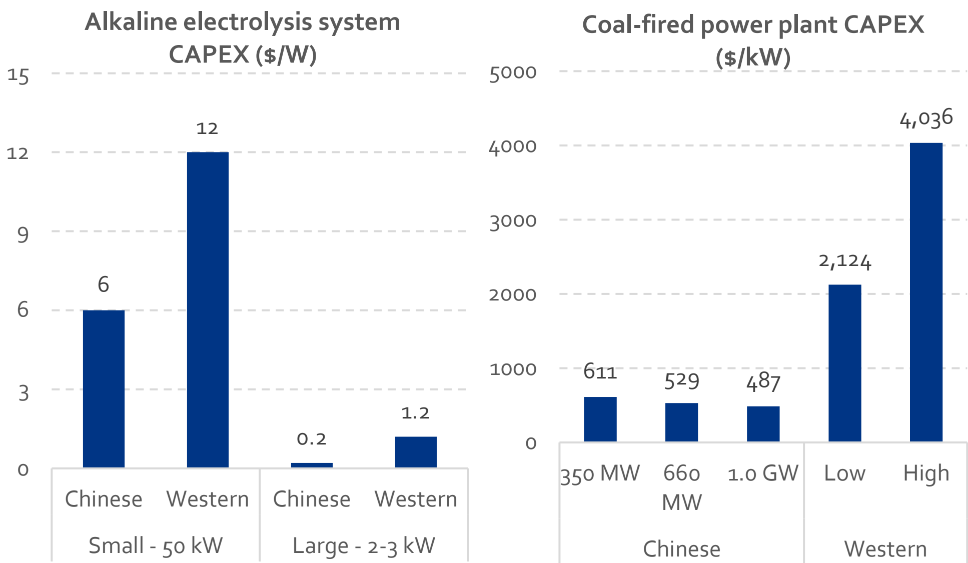
SWOT analysis is a strategic planning technique used to help identify strengths, weaknesses, opportunities, and threats related to business competition or project planning, it has been widely used for strategy formulation by constituting an important basis for learning about the situation of the studied object and for designing future strategies to solve the existing problems. In this section, a simplified SWOT analysis is conducted to identify the most important strengths, weaknesses, opportunities and threats of CCUS development in China, aiming to shed light on prospects of CCUS in achieving China's carbon neutral goal.

Strengths

Ability to significantly bring down unit manufacturing cost through industrial network clustering and economy of scale is the most important advantage of CCUS development in China: Chinese manufacturers and contractors have the capability to significantly bring down unit production cost offered by foreign competitors over a wide range of products. One of the key reasons for lower manufacturing cost in China is industrial network clustering, which refers to the practice of locating all or most of the key enterprises in an industry's supply chain in close physical proximity with each other. Following a rapid industrialization process starting from 1978, China has now formed a comprehensive modern industrial system comprising 41 large industrial categories, 207 medium industrial categories and 666 small industrial categories, and thus is the only country in the world that has all the industrial categories based on the industrial classification of the United Nations.[104]

Taking CAPEX of alkaline electrolysis systems and coal-fired power plants as examples, Figure 8-1 clearly indicates that Chinese manufacturers and contractors possess significant cost advantages against their counterparts in western countries. Consequently, though labor costs in China are expected to rise over time, comparative cost competitiveness of Chinese manufacturers and contractors is expected to stay and benefit China's CCUS development in the years to come. As a result, CCUS technologies possesses great potential for cost reductions in China, with cost of integrated CCUS facility in China projected to reach 310-770 RMB/tCO_2 by 2030 and then further decline over time to 140-410 RMB/tCO_2 by 2060.[105]

Figure 8-1: Comparative Cost Advantages of Chinese Manufacturers and Contractors[106]



China's enormous theoretical geological carbon storage capacity is another significant advantage. At 1,210 to 4,130 billion tons, China has the world's second largest theoretical geological capacity for CO_2 storage, behind only the United States.[107]

Furthermore, CCUS technology has huge coupling potential and application space with the conventional coal-based energy industries, including coal power and the coal chemical industry. There are numerous, widely distributed, and diverse types of large-scale and centralized coal-based emission sources suitable for the carbon capture.[108] In particular, many large stationary carbon sources are in close proximity with sink locations. There is at least one potential storage site within 100 kilometers (km) of 65% of China's existing power and industrial facilities.[109] As 60% of China's coal-fired power plants are under 10-year old, this advantage could provide large potential for CCUS retrofits of young coal-fired plants and help avoid large amount of emissions while minimizing stranded climate assets.[110]

Last but not least, China has diverse channels and scenarios for CO2 utilization thanks to its complete set of industries and diverse industrial supply chains. Breakthroughs on CO2 utilization could bring additional benefits to enterprises by offsetting significant portion of expenditures related to CCUS deployment in China.

Weaknesses

The most substantial barrier for CCUS development is its high upfront capital cost, which includes the cost for equipment installation and land occupation-related investment. The cost of CCUS technologies plays an enormous role in determining its large-scale deployment. Currently, within the CCUS process chain, carbon capture is the most expensive and energy-intensive segment. In 2019, capture cost for low-concentration CO_2 in China is estimated at about 300 to 900 RMB/tCO_2. The most common CO_2 transportation option in China, through a tanker, costs about 0.9 to 1.4 RMB/tCO_2.km. Pipeline transportation costs about 0.3 RMB/tCO_2.km at the Jilin Oilfield project. Flooding and storage technologies generally cost between 120 to 800 RMB/tCO_2, depending on technical details, reservoir conditions, gas sources, and source-sink distance.[111]

The lack of CCUS-related regulatory framework is another key barrier. At the national level, existing CCUS policies are more directive rather than compulsory, in sharp contrast with renewable energy development which is regulated by the Law of Renewable Energy.[112] Other regulatory weaknesses related to CCUS development include insufficient information for the operationalization of projects, weak market stimulus, and a lack of financial subsidies and complicated approval process.[113]

Finance-related challenge is another impeding factor for China's CCUS development. Unlike some developed countries, existing CCUS projects in China are primarily funded by SOEs through restricted investment channel. Without participation and investment from other market players, commercialization of emerging CCUS technologies could be set back in China.[114]

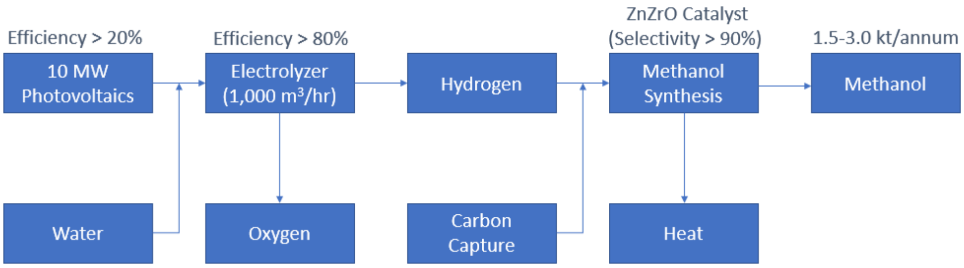
Opportunities

In 2020, operational coal-fired power capacity, steel output, cement production, and chemicals sales in China account for 52%, 56.5%, 55% and 40.6%[115] of global total, respectively. According to IEA (2021), CCUS in Chinese power, steel, cement and chemical sectors alone are projected to contribute to more than 2 billion tCO_2 abatement in 2060 under the Announced Pledges Scenario (i.e., peaking national carbon emissions before 2030, achieving carbon neutrality before 2060).[116] In other words, from the upstream supply perspective, there is great potential to promote CCUS development in China's power, steel, cement and chemical industries.

China also has abundant opportunities for developing CCUS hubs in areas with existing CO_2-EOR projects. CCUS hubs are industrial centers with shared CO_2 transport and storage infrastructure, which are crucial in accelerating CCUS deployment. Four potential CCUS hubs have been identified in six of China's northern and central provinces (Xinjiang, Shanxi, Shaanxi, Heilongjiang, Jiling, and Sichuan). The selected CCUS hubs are estimated to have the potential to cover 665 MtCO_2/annum.[117]

CCUS could also contribute to decarbonizing China's new energy sectors. For example, though China is the world's largest hydrogen producer and consumer, its hydrogen flow is nevertheless dominated by fossil fuel especially coal gasification.[118] When combined with CCUS, fossil-fuel based grey or black hydrogen in China could be converted into blue hydrogen, with substantial climate benefits.

Figure 8-2: Flow Diagram of China's First kilotons-scale E-Methanol Demonstration Project



Another potential application is production of e-methanol (please refer to chapter 6: Power to X in the Chinese energy system for further detail), which can be obtained from CO_2 captured from industrial point sources and green hydrogen through a one-step catalytic synthesis process. In November 2020, the test run of China's first kilotons-scale pilot e-methanol plant was successfully conducted in Lanzhou, Gansu Province. Designed by Dalian Institute of Chemical Physics, the plant consists of an alkaline electrolyser plant with a power capacity at 10 MW, splitting water in green hydrogen and oxygen, using renewable energy from nearby PV panels. According to Can Li (2020), annual output of the plant configured with 10 MW PV power capacity ranges from 1.5 to 3.0 kilotons of e-methanol (nicknamed as "liquid sunshine fuel" in the Chinese context).[119] As production capacity of the Northern-C-Methanol project under construction in Europe reach 45 kt/year,[120] prospects of commercializing e-methanol manufacturing with carbon capture become promising in an increasingly carbon-constrained world.

To achieve carbon neutrality before 2060, "negative emissions technologies" (NETs) that remove and sequester CO_2 from the atmosphere are expected to play a role in China. Bioenergy with CCUS (BECCUS) is the process of combining biomass utilization through combustion, fermentation, pyrolysis or other conversion methods with CCUS, thereby removing CO_2 from the atmosphere. As the carbon in the biomass comes from CO_2 extracted from the atmosphere by the biomass when it grows, BECCS is considered as technologically viable NET. In comparison, direct air capture (DAC) is a technology that captures CO_2 directly from the air with an engineered system. Though their wide deployment is constrained by cost and availability of biomass, BECCS and DAC are projected by leading Chinese research institutions to be responsible for emissions reductions of 300-600 $MtCO_2$ and 200-300 $MtCO_2$ by 2060, respectively.[121]

Threats

From a technological perspective, there are environmental and legal risks associated with possible CO_2 leakage from CCUS projects. CO_2 leakage could occur during capture, transportation, utilization, and storage, which will inevitably lead to negative impacts on the ecological environment and safety of people in the nearby area.[122] In particular, undesired loss of CO_2 from storage sites can occur due to imperfect storage sealing. Coupled with potential seepage from storage sites, the damages that carbon leakage might cause can be distinguished between local and global. From the local point of view, meaning a few kilometers around the storage site, concentrated CO_2 leakage could be harmful for people and livestock, which is evidenced by the unfortunate limnic eruption at Lake Nyos in northwestern Cameroon that killed 1,746 people and 3,500 livestock in August 21, 1986.[123] From a global climate perspective, doubt towards long-term reliability of storage sites may hinder the perceived effectiveness of CCUS as a reliable climate mitigation option.[124]

Another risk of CCUS deployment is the lack of resilience against the ongoing power sector transformation. Though coal-fired power plants in China are typically baseload power generators, they are expected to increasingly operate in peak-shaving mode to better support grid integration of variable renewables. Under such a dispatchable operation mode (e.g., a few hundred hours per year), CCS retrofitting of coal-fired power plants would be difficult to be justified from a unit abatement cost perspective. In comparison, if CCS retrofitting help coal-fired power plants continuously operate as baseload power generators, it would not only lead to forgone environment improvements associated with diminishing coal mining and transport activities, but also negatively impact potential of China's renewable and energy storge development in the years to come.

Last but not least, wide deployment of CCUS in hard-to-abate sectors may be vulnerable to "carbon leakage". After China kicked off its national emissions trading scheme in the power sector on July 16, 2021, the coverage of national ETS is expected to be extended to other emissions-intensive sectors including steel, cement and chemicals. Similar as the European Union (EU), China is expected to eventually face the dilemma of how to combine meaningful incentives for emissions reductions (via high carbon prices) while avoiding the risk that regulated companies may simply shift production and emissions offshore - a phenomenon known as "carbon leakage". To address the above challenge, the EU is unfolding its carbon border adjustment mechanism (CBAM). Given the unilateral nature and questionable WTO compatibility of the EU CBAM, it has not been well received by the EU's major trading partners including China. Unless a global solution could be explored to tackle carbon leakage-related concern, wide deployment of CCUS is difficult to be sustained in countries with high carbon prices.

8.4 Concluding remarks

According to Jaccard (2005), combining CCUS technology with continued fossil fuel use has good prospects in certain regions of the world, especially those characterized by high energy needs, plentiful fossil fuel resources, adequate prospects for carbon storage, and substantial challenges to scaling up renewables and nuclear power to a degree that would eliminate the use of fossil fuels in just a few decades.[125] As the world's largest producer and consumer of coal, and the top importer of all fossil fuel including coal, oil and natural gas, China has long recognized CCUS' potential to allow the country continuously utilize fossil fuel especially coal while simultaneously achieving deep carbon emissions reductions. Not surprisingly, CCUS policies in China have become increasingly proactive and supportive.

Nevertheless, unlike some other net-zero emissions technologies such as energy conservation, renewables-based electrification, bioenergy, green hydrogen, and enhancement of biological sinks, the Achilles' Heel of CCS deployment is the lack of auxiliary benefits other than carbon emissions abatement, which could easily be translated into verbal service by fossil fuel-reliant countries/companies without taking decisive near-term actions on national/corporate clean energy transition. Ideally, CCUS development should not lead to a noticeable reduction of nationwide efforts to support energy conservation, renewable and other clean energy development, both in R&D and financial terms. In absence of major technological breakthrough, CCUS should be positioned as the "last resort" backup technology to decarbonize hard-to-abate sectors where no viable alternative is available.

Given the nature of the landmark "carbon peaking and carbon neutrality" climate pledge, China's CCUS strategy should also be formulated in a phased approach. More specifically, before 2030, China should aim:

1. To further improve quality of energy and emissions statistical reporting: As reliable statistics are the foundation of sound energy and climate decision-making, China has already made significant efforts to improve quality of its basic energy statistics in the past, which is evidenced by major energy statistical revisions following each of the first three National Economic Census surveys conducted in 2004, 2008, and 2013. To ensure a smooth regulatory and market regime in support of CCUS development in the next decade, it is important for China to further improve quality of its energy and emissions statistical reporting.
2. To establish supportive and comprehensive CCUS regulations and standards. To promote CCUS R&D and commercialization in China, there are many regulatory deficiencies to be resolved, including the lack of an enforceable legal framework, insufficient information for the operationalization of projects, weak market stimulus, and a lack of financial subsidies and complicated approval process. In addition, CCUS-related standards should be improved to cover the entire industrial value chain from site selection to emissions abatement verification.
3. In the domestic front, China should eliminate all fossil fuel subsidies to stimulate market penetration of net-zero emissions technologies including CCUS. In the international front, China should proactively work with the EU and other like-minded countries with net-zero emission targets to explore a multilateral instead of unilateral solution for carbon leakage protection.

After 2030, China should aim to ensure a fair and transparent regulatory framework to allow CCUS compete with other net-zero technologies on an equal footing basis. In addition, China should also strive:

1. To continuously learn CCUS-related experience and lessons from regions with high carbon prices especially EU countries through enhanced international cooperation. Against the backdrop of the Green New Deal especially the legally binding 2050 climate neutral goal, carbon prices in EU ETS exceeded a record 60 euros/tCO_2 for the first time on August 30, 2021[126] and are expected to be increasingly higher in the coming decades. Consequently, prospects of CCUS deployment at scale are likely to be first tested in EU countries, with profound implications for its market penetration in other parts of the world including China.
2. While development of large-scale CCU projects may be stimulated by government imposed FYP targets or financial subsidies, deployment of large-scale CCS projects should in principle be driven by rising carbon pricing signal coupled with increasingly lower sectoral emissions cap set in accordance with the 2060 carbon neutrality goal. If so, large-scale geological storage of captured CO_2 emissions is expected to serve as China's "last resort" backup option to achieve carbon neutrality once all other viable alternatives are exhausted before 2060.

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China Energy Transformation Outlook

2022