

*Ready for CCS retrofit*

## *The potential for equipping China's existing coal fleet with carbon capture and storage*

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## Acknowledgements

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This publication is the culmination of a joint analysis project between International Energy Agency and China Electricity Council. Chinese Academy of Sciences also provided significant input. The process was facilitated by China's Administrative Centre for Agenda 21 (ACCA21), under the Ministry of Science and Technology (MOST).

China Electricity Council provided a detailed database of its coal-fired power stations, which was used to analyse the options for retrofitting. We thank Xiaojun Chai for leading the CEC engagement in this analysis and for the constructive comments throughout the work.

The Institute of Rock and Soil Mechanics of the Chinese Academy of Sciences analysed the various CO<sub>2</sub> storage options in China and helped match the power station fleet with the potential storage sites. We thank Xiaochun Li and Ning Wei for the analysis and comments provided throughout the project.

Jiutian Zhang and Xian Zhang from ACCA21 facilitated the analysis effort and contacts and provided comments. We thank you for the close collaboration not only on this project, but on various other projects throughout the years.

The main author of the analysis and this report was Simon Bennett of the IEA. Sean McCoy, Dennis Best, Tristan Stanley, Samantha McCulloch and Wolf Heidug of the IEA CCS Unit and Matthew Grey of the Climate Change Unit gave comments and suggestions. Juho Lipponen, Head of the CCS Unit, and Philippe Benoit, Head of Energy Environment Division, gave significant input and guidance. Luis Munuera helped generate the maps. Xie Xi of the ETP Division, on secondment at the IEA from ACCA21, provided proofreading. The IEA Publications and Printing Unit provided help with formatting and ensured the production of the final report.

Andrew Minchener of IEA Clean Coal Centre, Jon Gibbins, Liang Xi and Mathieu Lucquiaud of Edinburgh University, Jia Li of the UK Guangdong CCUS Centre, John Davison of IEAGHG and Robert Dahowski of Pacific North-West National Laboratory gave significant expert comments and suggestions to the study.



## Executive summary

Retrofitting carbon capture and storage (CCS) on existing coal-fired power stations in People's Republic of China (hereafter referred to as "China") represents a **major opportunity**, with significant benefits for emission reductions. In total, some 310 gigawatts (GW) of existing coal-fired power capacity meet a number of basic criteria for being suitable for a retrofit. This number is likely to increase, as new efficient plants are being commissioned during the next several years. Regardless of how much retrofitting will finally be required in a low-emissions pathway, this analysis indicates that there is ample potential available.

Simultaneously the world's leader in renewable electricity capacity and the world's largest emitter of energy-related carbon dioxide (CO<sub>2</sub>), China emitted some 8.6 billion tonnes in 2014. Around half of these emissions were from coal-fired power stations. China currently has around 900 GW of installed coal-fired power capacity, representing almost 50% of global coal-fired capacity, and has nearly 200 GW under construction. The existing power plants considered in this study represent potential emissions of **85 billion tonnes of CO<sub>2</sub> (GtCO<sub>2</sub>)**, if they continue to operate at current load factors for the remainder of their lives, even if smaller units are retired early. Despite such massive emissions, the Chinese coal-fired power fleet is on average one of the world's most efficient, as over two thirds of the capacity was built since 2005. As a result, the average operational efficiency of the Chinese coal fleet increased six percentage points in the last ten years, bringing it to the same level as that in OECD countries.

Through its "Intended Nationally Determined Contribution" (INDC) under the UNFCCC framework, China has committed to **peaking CO<sub>2</sub> emissions by 2030**. The enduring emissions from China's coal-fired power plants present a challenge to efforts to reduce greenhouse gas emissions beyond any peak. Coal use is also being shaped by policies to control local pollutants, which make low carbon electricity and power plant upgrades more attractive.

A part-solution can be found in **retrofitting existing coal-fired power stations with CCS**, which can reduce their emissions rate by around 85%. The emissions of a CCS-retrofitted coal plant are equivalent to less than a quarter of that of a combined cycle gas plant. In the best conditions, equipping a power plant with CCS only requires investment in the equipment for CO<sub>2</sub> capture, transport and storage and not in the power plant itself. In other situations, the power plant can be upgraded at the same time as CCS retrofit, delivering several additional decades of lifetime to the plant. In both cases, a CCS retrofit can avoid the need to write-off otherwise productive generating capacity, or otherwise limit its use, and be a cheaper option than a new low-carbon generation capacity.

In the IEA 450 scenario, intended to provide about a 50% chance of keeping long-term global average surface temperature rise to 2°C or less, some 185 GW of coal-fired power capacity in China in 2035 is retrofitted with CCS. The analysis of this paper forms the basis of the underlying assumptions on the potential for CCS retrofitting in China and confirms that such level of **retrofitting is feasible**.

This paper explores the factors and conditions that are pertinent to the future retrofit of CCS at any of today's coal-fired power plants in China. Several **key criteria** have been applied to analyse the existing fleet of coal-fired plants operated by members of the China Electricity Council (CEC) and to identify retrofit potential.

**Access to CO<sub>2</sub> storage** is a critically important criterion for retrofitting CCS on any power station. Proximity to a suitable storage site plays an important role in determining costs, and plants with high CO<sub>2</sub> transport and storage costs generally do not feature among the best candidates for CCS retrofitting in China. Analysis in this study suggests that 385GW of China's coal-fired plant would

find suitable storage capacity within a 250 km radius, but longer CO<sub>2</sub> transport distances can be attractive in some cases.

Other **suitability criteria** relate to the attributes of the coal-fired plant itself. Criteria used for this study are plant age, size, load factor and local or regional pollution control measures, and they have been used to determine whether a plant is likely to be a candidate for retrofitting. In total, some 310 gigawatts (GW) of existing coal-fired power capacity meet these criteria for being suitable for a retrofit. Plant size is of particular importance in China, where many smaller plants are likely to be retired before CCS retrofitting is widely deployed.

In addition, other **cost factors** influence a plant's relative attractiveness as a candidate for retrofitting with CCS. These factors include cooling type, efficiency, steam turbine design and pollution controls. Cost factors, including the indispensable costs of CO<sub>2</sub> transport and storage, have been used to rank candidate plants according to the cost premium for generating electricity with low emissions, and also to explore the relative impacts of different power plant attributes.

The costs of retrofitting are likely to vary significantly: the additional costs of power generation after retrofitting are estimated to vary between USD 34 and 129 (United States dollars) / MWh. Some 100 GW of existing capacity are estimated to generate additional power generation costs of less than USD 50 / MWh, indicating that a significant retrofit opportunity exists within a **reasonable cost range**.

The units with the very lowest retrofitting costs are recently constructed. However, units with low retrofit costs can have different combinations of short or long CO<sub>2</sub> transport distances, hard coal or lignite, water or dry cooling, simple retrofits or retrofits with steam cycle rebuilds. This analysis highlights that it is **unwise to set too rigid retrofit criteria** or thresholds. On the contrary, it is necessary to include as many relevant factors as possible when guiding the search for retrofit candidates or when setting policy to stimulate investments in CCS retrofits.

Retrofitting can represent a significant opportunity for emission reductions in China, but it will require establishing the right drivers. This has several implications for **strategy and policy** in the Chinese context. Three particular areas merit further work and policy consideration from the Chinese government and industry:

- Including CCS in Chinese climate policy, or retaining the option of future CCS retrofits, makes it imperative to continue work to analyse **CO<sub>2</sub> storage opportunities** and to develop actual project-level storage sites.
- Government and industry should continue their efforts in **technology innovation** and cost reduction, to further bring down costs of CCS in general and retrofitting in particular.
- Finally, given ongoing permitting of new coal-fired power stations, promoting **CCS-readiness** of new power stations can be an effective tool. Advancing CCS-readiness merits further attention by Chinese policy-makers in order to ensure that future retrofitting opportunities are maximised. In this regard, attention to the location of new plants is likely to be of particular importance.

Retrofitting existing coal-fired power stations with CCS in China represents a significant opportunity to manage CO<sub>2</sub> emissions while continuing to use the vast coal-based infrastructure that China has been expanding rapidly in recent years. Ensuring that CCS technologies are available in China over the next two decades will require effort from a variety of stakeholders in industry and government, alongside other measures to maintain energy security. This study presents an initial exploration of the key issues, and provides a foundation for more detailed plant-level assessments. Economic, employment and social benefits and trade-offs related to the inclusion of CCS retrofits within a strategic transition to a lower-carbon society in China are also important drivers and merit further consideration.

## Introduction

Coal use in the electricity sector worldwide is growing at the same time as concerns about future CO<sub>2</sub> emissions are translating into commitments to peak and then reduce emissions from fossil fuel use. The scale of coal-based infrastructure is vast and the many thousands of gigawatts of coal-fired power plants that have been constructed since 2000 are expected to continue to generate low-cost electricity for decades to come.

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In countries such as China, where coal resources are plentiful, coal production costs are low and alternatives are much less widespread, there is a mounting tension between climate ambitions and pollution reduction goals on the one hand, and installed energy assets on the other hand. Carbon capture and storage (CCS) is an emissions control technology that can alleviate this tension by allowing continued use of fossil fuel infrastructure with dramatically reduced emissions (Box 1). In fact, International Energy Agency (IEA) modelling suggests a significant role for the retrofit of CCS to power plants that were originally built without it if the worst outcomes of climate change are to be avoided (Box 2). But CCS is only an appropriate solution where favourable conditions, including access to suitable CO<sub>2</sub> storage sites, align.

In its 2012 analysis of the CCS retrofit potential in the global power fleet, the IEA analysed some of these conditions for China at a high level. The study estimated that over 300 GW of existing Chinese capacity could be highly suitable for addition of CO<sub>2</sub> capture (IEA, 2012). However, such a high level analysis sheds little light on the local factors that can influence CCS retrofits, such as policy conditions, costs and access to CO<sub>2</sub> storage, which is an inevitably local concern. The present study aims to build up a more informative picture of Chinese coal-fired plants and their attractiveness for retrofitting with CCS. It takes into account the cost implications of proximity to suitable CO<sub>2</sub> storage, and the wider Chinese policy context for coal-fired power plants. Furthermore, it aims to describe the various approaches to equipping power plants with CCS and the conditions that could make an investment in a CCS retrofit attractive. This analysis looks at the retrofit opportunity across a substantial plant fleet, looking at various technical and plant-level economic factors. Economic, employment and social benefits and trade-offs related to the inclusion of CCS retrofits within a strategic transition to a lower-carbon society in China are also important considerations.

The study is the result of a collaborative partnership between the IEA and the China Electricity Council (CEC), which has benefitted from invaluable input from the Chinese Academy of Sciences (CAS) and the Administrative Centre for China's Agenda 21 (ACCA21).

In the next section, the background to the study is described in the context of the Chinese energy mix and policy environment. Following this, the techniques, costs and benefits of CCS retrofitting are discussed. The main analysis is presented starting with the criteria that might determine whether a power plant is a suitable candidate for CCS, and the share of coal-fired plants operated by CEC members that meet these basic criteria. To assess the relative attractiveness of these candidate plants, the additional costs of electricity generation that they would incur from the addition of CCS are estimated and compared. The final section of the report summarises some of the main implications that emerge from the analysis, including the importance of cost reductions through innovation and locating new power plants such that the costs of future CCS addition can be minimised.

**Box 1 • Power generation with CCS: a source of low emissions electricity**

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CCS involves integration of three processes: separation of CO<sub>2</sub> from mixtures of gases such as flue gas and compression of this CO<sub>2</sub> to a liquid-like state (CO<sub>2</sub> capture); transport of the CO<sub>2</sub> to a suitable storage site (CO<sub>2</sub> transport); and injection of the CO<sub>2</sub> into a deep geological formation where it is retained by a natural (or engineered) trapping mechanism and its behaviour monitored to ensure permanence (CO<sub>2</sub> storage). As well as with fossil fuels, CCS may also be used in combination with sustainable biomass (BECCS), enabling so-called “negative emissions”. CCS makes possible the near elimination of CO<sub>2</sub> emissions in the power and industrial sectors while allowing for the continued use of fossil fuels, acting as a protection strategy for assets that would otherwise be decommissioned during a transition to a low carbon economy.

In China, CCS is being primarily considered for avoiding CO<sub>2</sub> emissions from applications such as coal-to-chemicals production via gasification and coal-fired power generation (ADB, 2015). The first projects under consideration and development aim to minimise costs by combining CO<sub>2</sub> capture from coal gasification, which has lower costs than CO<sub>2</sub> capture from coal combustion in power plants, with CO<sub>2</sub> utilisation in enhanced oil recovery (EOR), which can increase economic returns through the resulting oil sales. EOR is a process by which CO<sub>2</sub> injection into an oilfield can increase oil production and under certain conditions can lead to permanent geological CO<sub>2</sub> storage (IEA, 2015b). These first projects will provide invaluable experience for the Chinese government and companies to expand CCS activities over the next decade to include pulverised coal and gas-fired power plants, including CCS retrofits of installed plants, combined with CO<sub>2</sub> storage in saline aquifers.

CCS is an option that can be retrofitted to coal, gas or biomass-fired power plants that are already in operation if they meet certain criteria. The retrofit of existing plants with CCS can provide plants with a new lease on life as low-carbon generators, which could be particularly important in countries like China that already have a large fleet of coal- and gas-fired power plants, and where coal prices are anticipated to remain relatively low.\* China's INDC states that China will “strengthen research and development (R&D) and commercialization demonstration for low-carbon technologies, such as energy conservation, renewable energy, advanced nuclear power technologies and carbon capture, utilization and storage” (NDRC, 2015).

By the end of 2015, 15 large-scale CO<sub>2</sub> capture projects were operating globally across five sectors, with the potential to capture up to 26 MtCO<sub>2</sub> per year. Over the past five years there has been a slow but steady increase in the number of CCS projects under construction, which should lead to the start-up of an additional four-five projects during 2016 or by early 2017. A further dozen projects are in advanced stages of planning, including four in China. These four projects are the PetroChina Jilin Oil Field EOR Project (Phase 2), Sinopec Qilu Petrochemical CCS Project, Sinopec Shengli Power Plant CCS Project and Yanchang Integrated Carbon Capture and Storage Demonstration Project. The last two of these will operate CCS at power plants.

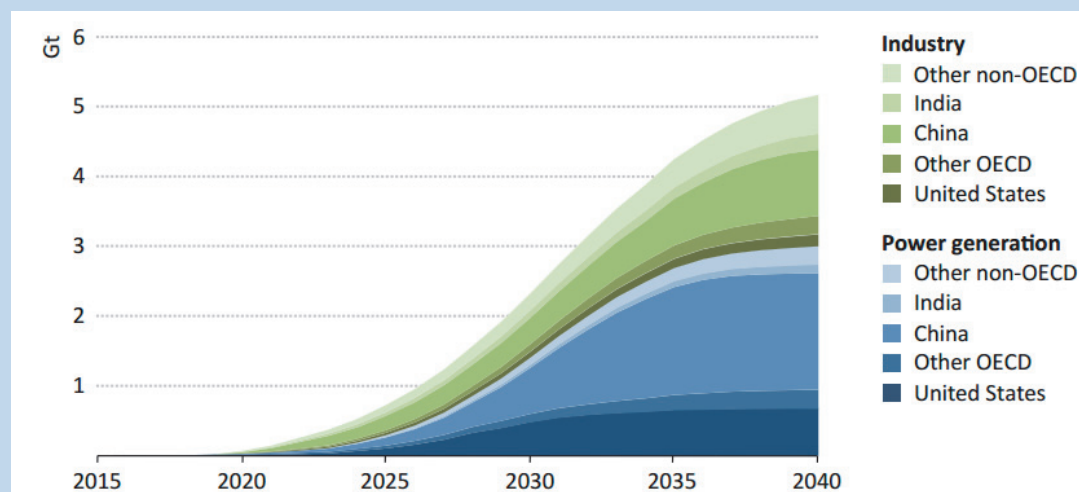
\* If global demand for coal weakens due to policies and investments that aim to mitigate climate change, coal import prices in China may be further depressed by the same drivers that would stimulate CCS deployment over the longer term.



## Box 2 • The role of CCS in climate change mitigation globally

In IEA scenarios that aim to stabilise global average surface temperatures no higher than 2 C above pre-industrial levels, and at lowest cost, adoption of CCS increases from around the mid-2020s (the below figure). It is not projected to be deployed at scale in all countries, but is an important part of mitigation strategies in China, North America, India and the Middle East. Without CCS, more pressure would be placed on other technologies and sectors to deliver even greater emissions reductions.

The impact of CCS in this WEO 450 scenario can be seen most strongly in the power sector where capacity begins to increase notably from the 2020s (averaging 20 GW per year), growing rapidly in the 2030s (averaging 50 GW per year) (IEA, 2015a). Global capacity of CCS-equipped power plants reaches 740 GW in 2040, 20% of fossil-fuelled power generation capacity at that time. The global average CO<sub>2</sub> intensity of all power generation in this scenario falls to around 85 g/kWh in 2040, around one-tenth of the level of an unabated coal-fired power plant and one quarter of the level of an unabated gas-fired power plant. Without CCS, neither coal nor gas-fired power plants could retain the significant market share that they have in the 450 Scenario (in which gas-fired generation would account for 16% of total generation in 2040 and coal-fired generation account for 12%).



Source: IEA, 2015a.

# An energy challenge for China

## Key points

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**Coal remains the energy basis for a major part of the Chinese economy and China's coal-fired power plants are relatively young. Peaking and reducing China's energy sector emissions will require solutions for China's coal-fired power fleet.**

**Few small coal-fired units are likely to still be operating at the end of the 2020s in China, even if they have been constructed since 2000. This is part of an ongoing trend to increase the sizes and efficiencies of coal plants and, potentially, to distribute them further from population centres.**

**To the extent that any new coal-fired power plants are constructed in China, then China's ability to peak electricity-sector emissions will require that some existing plants are retrofitted with CCS or are retired.**

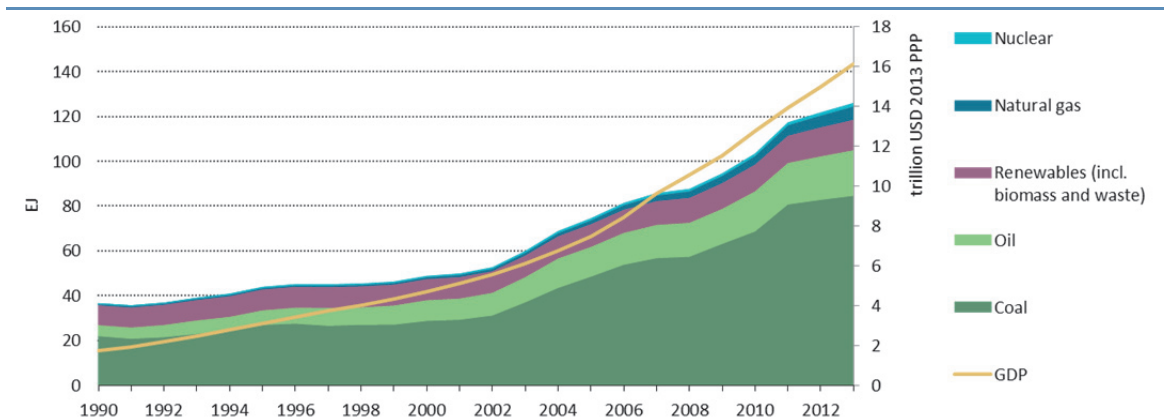
China has taken significant steps to protect its population and the environment from pollution in recent years. It continues to develop policies and actions that address issues including air quality, natural resource management and climate change. In June 2015, China's Intended Nationally Determined Contributions (INDC) was submitted to the United Nations Framework Convention on Climate Change (UNFCCC) and, among other things, it sets out a target to peak CO<sub>2</sub> emissions in 2030, or earlier if possible (NDRC, 2015).

This section outlines the dominance of coal in China's energy supply and recent developments in the power generation sector. This is followed by a discussion of the possible trends emerging from an orientation of Chinese policy towards addressing environmental concerns.

## The current dominance of coal in China's energy supply

In a little over two decades, China's primary energy demand has increased more than threefold and its GDP sevenfold (Figure 1). Its installed power generation capacity expanded from 137 GW in 1990 to 1 198 GW in 2012, while over the same period electricity generation rose from 650 TWh to 5 024 TWh (IEA, 2015d). This unprecedented growth has accompanied a transformation in China's economy and lifted more than 400 million people out of extreme poverty (Wang, Gao and Zhou, 2006).

Figure 1 • Total primary energy supply from different sources and GDP in China since 1990



Source: IEA statistics.

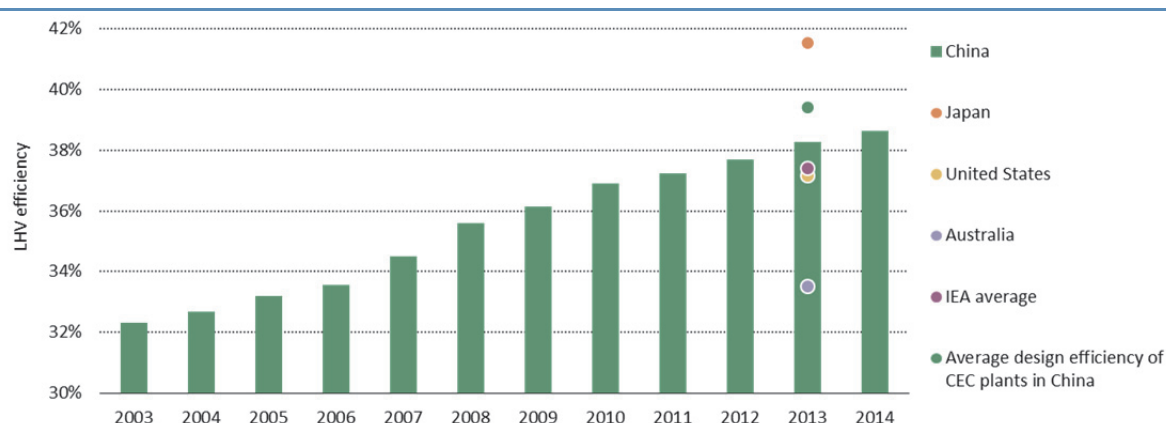
The expansion in China's economy has been fuelled primarily by fossil fuels, particularly by coal, which is the most abundantly available and lowest cost fossil fuel in China. The contribution of fossil fuels to total primary energy supply rose from 76% in 1990 to 88% in 2012, while coal's share of energy supply rose from 61% to 68% in the same period. Coal's dominance of electricity generation has been nearly constant over the period, and was 73% in 2014. Over the last decade, more than 85% of the increase in global coal demand has come from China.

## The dominance of coal-fired power

The installed capacity of coal-fired power plants in China rose from 272 GW in 2005 to around 900 GW by the end of 2015 and now represents almost 50% of global coal-fired capacity, with a further 150 GW to 200 GW under construction (CEC, 2015a; Platts, 2015; Global Coal Plant Tracker, 2016). Members of China Electricity Council operated over two thirds of Chinese coal-fired capacity in 2012. This paper focuses on the 560 GW of CEC coal-fired units that are 200 MW or larger and were operational as of the end of January 2014 (referred to hereafter as "CEC plants").<sup>1</sup> These plants produced 89% of China's coal-fired electricity in 2012 and 2013. The information and conclusions for CEC plants are broadly applicable to the entire coal-fired fleet in China. For example, the split of Chinese coal-fired capacity by steam conditions – 61% subcritical, 25% supercritical, 15% ultra-supercritical – closely matches the split of CEC coal-fired capacity.

The average efficiency<sup>2</sup> of CEC plants has risen in recent years (Figure 2). This is a result of the closure of many older, smaller subcritical power plants and the addition of larger, supercritical units. Since 2005, 437 GW of capacity began operating, 295 GW (68%) of which is in units of 600 MW or larger. Average operational efficiency remains almost two percentage points below the average design efficiency due to efficiency losses in part-load operation, variations in environmental conditions and the order in which plants are dispatched on the Chinese electricity grid. Nevertheless, average operational efficiencies of CEC plants have reached a level that exceeds the average across coal-fired plants in IEA member countries.

**Figure 2 • The rising operational efficiency of China's coal-fired power fleet**



Source: China Electricity Council (CEC), IEA statistics.

In addition to efficiency improvements of coal-fired power plants, China has increased the share of other sources of electricity in recent years (Table 1). Financial incentives have driven capacity additions of non-hydro renewable sources to record levels, reaching 29 GW in 2014 and

<sup>1</sup> The 68 GW of coal-fired capacity under construction in China in 2015, and the 406 GW in planning are not considered in this study due to a lack of unit-level information or certainty about their realisation.

<sup>2</sup> Unless otherwise stated, all efficiency values are given as low heating value (LHV) efficiencies.

delivering 3.4% of electricity generation. Wind and solar deployment continues to face challenges to secure grid connections and the rapid introduction of wind capacity has led to a significant increase in the curtailment rate of wind power as grid operators favour thermal generation (BNEF, 2015a). As these problems are overcome, coal is likely to represent a declining share of electricity generation. However, this may not result in an end to new coal capacity for two reasons:

- New coal capacity often replaces older coal plants, increasing overall efficiency.
- Despite a falling share for coal, total electricity demand is expected to grow over the medium-term.

**Table 1 • Power generation capacities and shares of electricity sources in China in 2014**

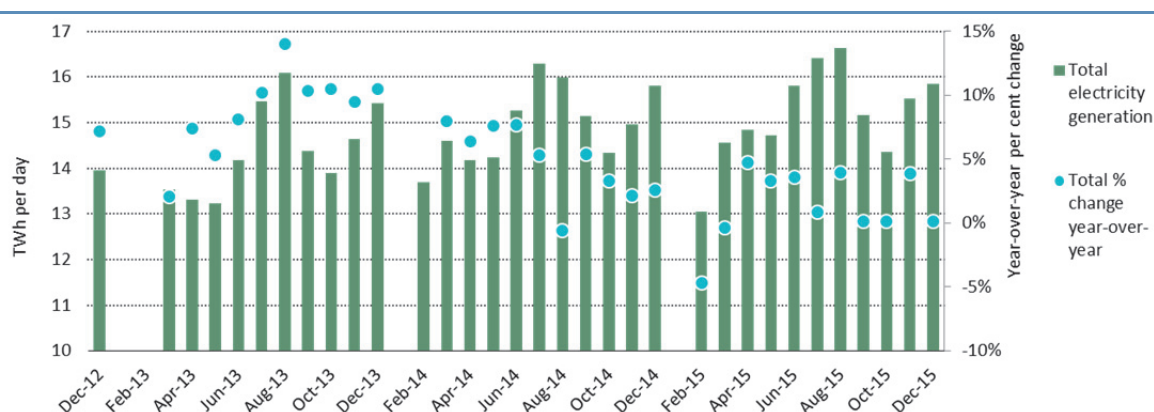
Source	Capacity added in 2014 (GW)	Total installed capacity (GW)	Share of 2014 electricity generation
Coal	39	825	73.0%
Hydro	22	280	19.2%
Wind	21	96	2.8%
Natural gas	8	56	2.2%
Nuclear	5	20	2.3%
Solar	8	27	0.4%

Note: Hydro does not include pumped storage hydro.

Source: IEA 2014a, CEC 2015b, NEA 2015, BNEF 2015b.

Total electricity generation increased 3.6% in 2014 compared to 2013, but in 2015 the first year-on-year decreases in electricity consumption were experienced in February and July, which could translate into slowing growth for coal use (Figure 3). Scenarios developed by China (for the Deep Decarbonization Pathways Project, DDPP) and IEA WEO show the year-on-year growth in electricity demand falling to between 1.5% and 3.5% on average between 2020 and 2030, and between 0.5% and 1.5% between 2030 and 2040 (Figure 4). However, even if the share of coal-fired generation in China were to fall to 50% by 2040, China would still be expected to add more coal-fired capacity than any other country between now and 2040 (IEA, 2015c).

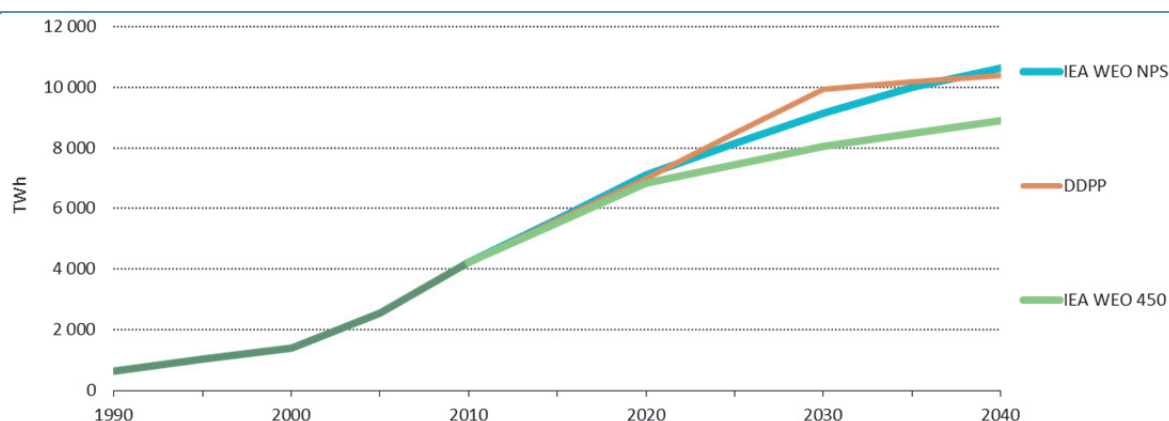
**Figure 3 • China's electricity generation since July 2012**



Note: Data for January and February 2013 and January 2015 are missing.

Source: China National Bureau of Statistics, 2015.

**Figure 4 • China's electricity demand under IEA WEO and DDPP scenarios**



Note: WEO = IEA World Energy Outlook 2014 publication, which presents modelled scenarios of the future world energy system. NPS = New Policies Scenario, which takes into account the policies and implementing measures affecting energy markets that had been adopted as of mid-2014, together with relevant policy proposals, even if specific measures needed to put them into effect were not yet developed. 450 = a scenario that assumes a set of policies that bring about a trajectory of greenhouse gas emissions from the energy sector consistent with the international goal of limiting the rise in long-term average global temperature to 2°C.. DDPP = Deep Decarbonization Pathways Project.

Source: IEA, 2015c; DDPP, 2014.

## An evolving environment for policy and the Chinese energy mix

In recent years, the energy and environmental policy outlook in China has developed rapidly. Various government initiatives have been developed with clear potential to change the outlook for new and existing coal-fired power plants and to support the development of CCS. In June 2014, President Xi Jinping called for an “energy production and consumption revolution” to address the challenge to advance economic development and energy security while protecting the environment (Xinhua, 2014). In the same year, Premier Li Keqiang declared a “war against pollution” (Reuters, 2014).

In the power sector, four drivers are most apparent:

- The desire to reduce the health and social costs of local air pollution.
- The opportunity to diversify the electricity supply mix for energy security purposes.
- A rising commitment to greenhouse gas emissions reductions.
- Concern regarding access to natural resources, such as water.

At the national level, China's INDC sets out its headline targets for 2030 (NDRC, 2015) and extends existing national targets for 2020 (State Council, 2014; NDRC, 2014a):

- Peak of CO<sub>2</sub> emissions in 2030, or earlier if possible.
- Lower CO<sub>2</sub> emissions per unit of GDP by 60% to 65% from 2005 levels.
- A share of 20% non-fossil energy in the total primary energy supply by 2030.
- New coal-fired power plants to consume no more than 300 grams of coal equivalent (gce)/kWh (40.9% efficiency) from 2014, and an operational average for all plants of 310 gce/kWh by 2020.
- Total primary energy supply cap of 4.8 billion tonnes of coal equivalent (tce) (141 EJ) per year by 2020 (an average annual growth rate of 1.5% from 2013 to 2020), with a cap on the share of coal of 62% (87.2 EJ) by 2020 (an average annual growth rate of 0.4% from 2013 to 2020).

These targets, and other considerations, translate to detailed policy environments for local pollution, greenhouse gases, energy mix, and natural resource availability at an operational and

investment level. There is considerable overlap between these areas and only the overall combination of these policy drivers can give the context for the future of China's electricity sector. A summary of the main Chinese policy statements and standards in these four areas is provided in Annex 1.

The future impacts of China's environmental, energy and economic policies on its coal-fired power plant fleet remain uncertain. However, some trends are evident.

### ***Trend 1: Substitution of smaller, older plants by more efficient ones***

China has undertaken measures to modernise its power generation fleet. The 11<sup>th</sup> FYP (2006-10) emphasised the closure of units of under 100 MW and improvements to the efficiency of units between 200 MW and 300 MW. Under these arrangements, companies' expansion of generation was contingent on the closure of smaller, older plants. For example, addition of a new 600 MW unit required closure of 420 MW of old capacity, while a new 1 000 MW unit of generation was conditional on the closure of 600 MW (NDRC, 2007).

This policy led to closure of 77 GW of smaller plants by 2010, with a further 20 GW of closures foreseen for the 12<sup>th</sup> FYP period (NEA, 2013). Requirements of the Instruction Opinions on Solving the Problem in Overcapacity issued by the State Council also contributed to the closure of 4.47 GW of small thermal power units in 2013 (NDRC, 2014b). As a result of the combination of these measures, over 100 GW of capacity has been closed by 2014 (Burnard, 2014). In July 2015 it was announced that a further 4.2 GW would be closed by the end of 2015 and that the eight major state-owned coal-fired electricity providers had been given strengthened targets for the amount of their capacity that should be upgraded to meet emissions and efficiency requirements in the next year (Bloomberg BNA, 2015).

In 2004 it was announced that only new coal-fired plants with capacities of 600 MW or larger would be eligible for approval, except in Tibet, Xinjiang and Hainan, and that in eastern coastal areas an efficiency of 275 gce/kWh (44%) would have to be met (NDRC, 2004).<sup>3</sup> Since 2014, efficiency requirements have been further refined and extended nationwide with a national maximum of 300 gce/kWh and new operational efficiency targets for different types of generators for 2020 (NDRC, 2014a).

It can reasonably be expected that coal-fired units of 100 MW or smaller will not still be operational in China in the 2020s. Furthermore, it appears that most units smaller than 600 MW will not be operated for longer than their technical lifetimes of 30 years.

### ***Trend 2: Limitations on urban coal use and rises in coal consumption in northern and western provinces***

The policies for the reduction of local pollution in populated areas are likely to have an impact on the distribution of coal-fired power plants in China. Currently, the provinces of Shanxi, Shaanxi and Inner Mongolia account for 60% of all Chinese coal production, while only 18% of CEC coal-fired generation capacity is located in these provinces (Figure 5). The Chinese government has identified five key regions in the North West of the country to be priority areas for development of large-scale coal generation capacity concentrated near coal mines.<sup>4</sup> The additional costs of transporting electricity to population centres are thought to be offset by the avoidance of coal

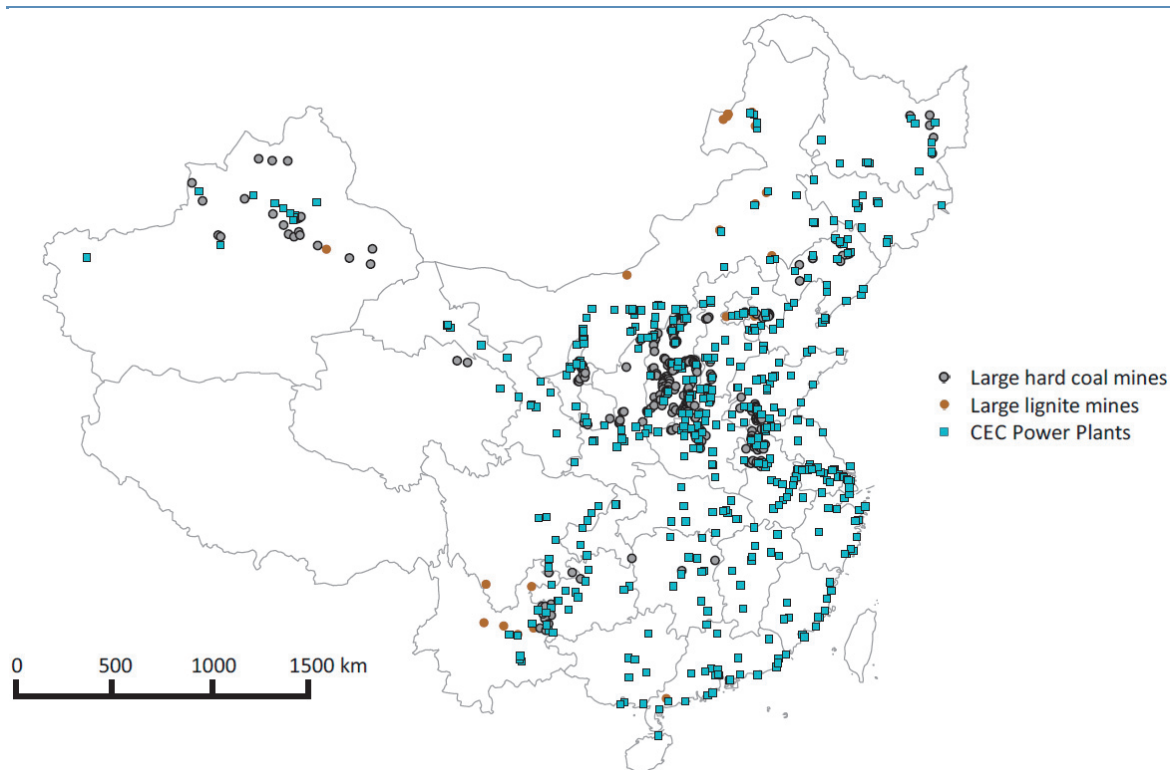
<sup>3</sup> In this declaration, units outside eastern coastal area were given a lower efficiency target for new plants, up to 305 gce/kWh (40%) for dry-cooled plants in coal-rich regions. Exceptions to the unit capacity threshold were also made for units burning low-grade coal or coal wastes and CHP units in urban areas.

<sup>4</sup> These regions are Inner Mongolia, Ningxia, Shaanxi, Shanxi and Xinjiang.



transport or import costs. Construction of new coal plants in other regions is being strongly discouraged in the near-term by the Chinese government.

**Figure 5 • Major coal mines and coal-fired power plants in China in 2013**



Note: This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Source: CEC, United States Geological Survey (USGS) 2014.

Construction of new power plants in locations closer to coal production might help improve public health across the population, while also avoiding freight costs that can be high enough to push the costs of domestic coal above those of imports. However, it should be noted that several of the net coal exporting provinces are those with the greatest concerns regarding future water availability (IEA, 2015c). As a result, new coal-fired capacity, which has a relatively high added value economically, may compete for water and government support with agricultural production and other industries in these areas. Furthermore, losses due to long distance transmission of electricity from more remote regions could partly counteract the efficiency improvements associated with larger, more modern plants, and thus offset some of the greenhouse gas emissions benefits.

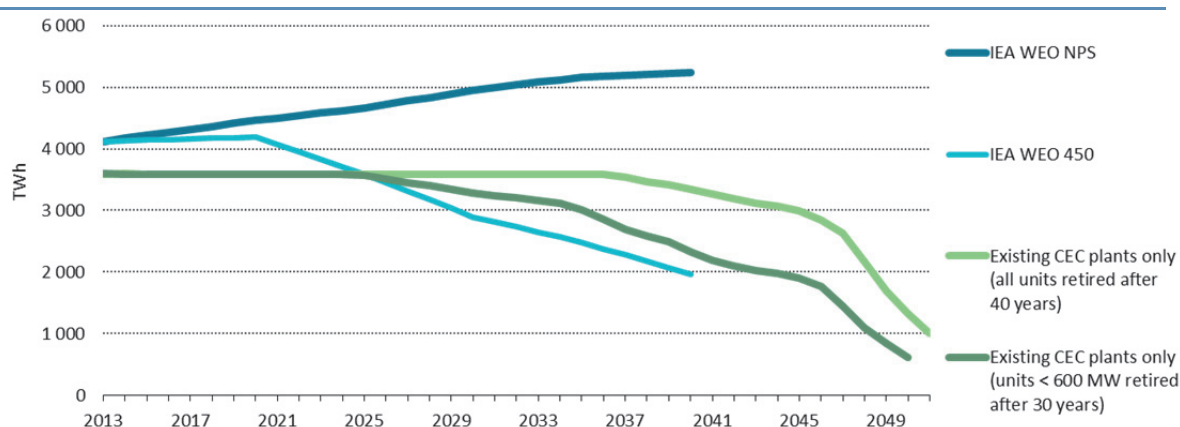
There would be a more detrimental effect on greenhouse gas emissions could be seen if synthetic natural gas (SNG), rather than electricity, were produced from coal in the coal-mining provinces and piped to more populated regions to the south and east for electricity generation in combined cycle gas turbines (CCGT). While local pollution from CCGTs is much lower than that from coal plants using state-of-the-art pollution controls, lifecycle emissions of synthetic natural gas-fired electricity can be 60% higher per MWh than those from a coal-fired plant (Jaramillo, 2007). This difference can, of course, be mitigated by the application of CCS to the production of SNG.

Overall, the government's five priority areas in the North West are more likely regions for coal-based infrastructure investments, but this is not guaranteed.

### Trend 3: Slower increase then peak in coal-fired power generation

Coal-fired power generation is projected to grow in China, despite policies aimed at reducing pollution and increasing the efficiency of coal use, but at a much lower rate. While coal-fired power generation grew on average by 10.4% per year between 2003 and 2013, recent trends indicate that the annual growth rate under existing policies may fall to just 0.6% per year to 2020 and no more than 1% between 2020 and 2030 (IEA, 2015c, 2015e). At this rate, coal consumption for electricity would only grow by 11% by 2030. In such a scenario, existing CEC plants would make up a decreasing share of total coal-fired generation if all existing plants were operated until the end of a planned 40 year lifetime and then decommissioned (Figure 6). If smaller plants were retired earlier than 40 years, as is likely in China, this gap would be wider.

Figure 6 • Coal-fired electricity generation from existing CEC plants compared with IEA WEO scenarios



Note: WEO = IEA World Energy Outlook 2014 publication. NPS = New Policies Scenario, which takes into account the policies and implementing measures affecting energy markets that had been adopted as of mid-2014, together with relevant policy proposals, even if specific measures needed to put them into effect were not yet developed. 450 = a scenario that assumes a set of policies that bring about a trajectory of greenhouse gas emissions from the energy sector consistent with the international goal of limiting the rise in long-term average global temperature to 2°C. In the *early retirements of smaller units* scenario, units less than 300 MW are retired by 2025, while units less than 600 MW are retired after 30 years of operation.

Source: CEC; IEA, 2015c.

Any growth in coal-fired electricity would thus require new capacity, even at slow growth rates. Even if all CEC plants were operated at 90% load factors for their remaining lifetime (an increase of 25% compared to today's average load factors), their combined output could only sustain a 2.2% growth in coal-fired generation until 2020 and no further growth in the 2020s. However, if new policies are introduced and lead to coal-fired power generation peaking in China by 2030, no new capacity would be required. Overcapacity in coal-fired power plants could become real. China added a record amount of new coal-fired capacity in 2015 and continues to start new construction projects in 2016. However, in the near-term, construction of new coal plants has been suspended in 15 provinces until 2017, possibly indicating that overcapacity is already a concern (Polaris, 2016).

## Implication: constrained outlook for unabated coal creates opportunity for CCS retrofits

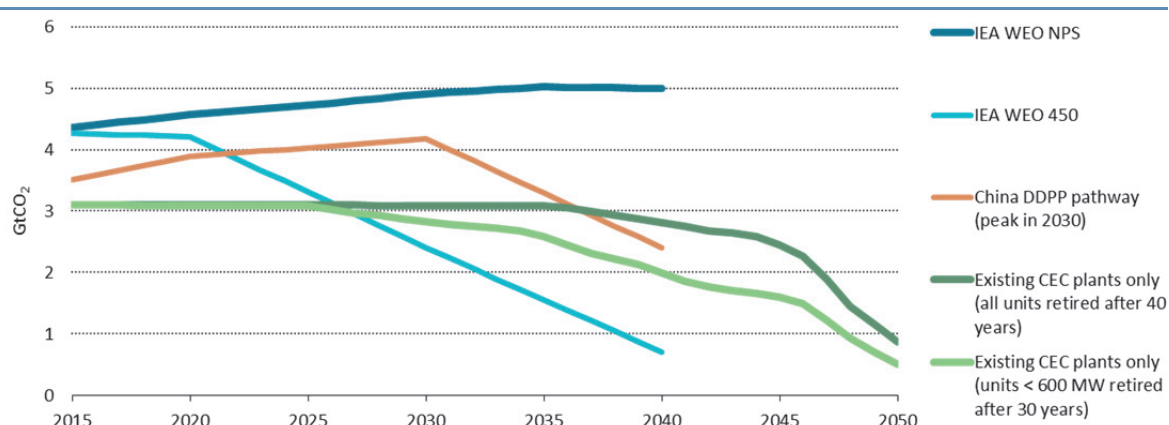
Based on IEA analysis of CEC plant-level data, existing CEC plants represent potential emissions of 85 billion tonnes of CO<sub>2</sub> if they continue to operate at current load factors for the remainder of their lives, even if units of 300 MW and under are retired early. The IEA's global scenario for keeping surface temperature rise to 2°C or below (WEO 450) includes emission of 71 billion tonnes of CO<sub>2</sub> from all Chinese power generation between 2015 and 2040.

If the WEO 450 scenario unfolds, the contribution of coal-fired electricity generation could be largely supplied by existing plants until after 2040 due to the increasing share of renewable and nuclear electricity. CO<sub>2</sub> emissions from all existing coal plants in China, however, would significantly exceed the emissions trajectory of all Chinese electricity generation in the WEO 450 scenario unless retirements were further accelerated from around 2025 onwards or a substantial proportion of existing plants were retrofitted with CCS (Figure 7).

Due to the recent construction of the vast majority of the Chinese coal fleet, plants that could face retirement or operational restrictions in order to reduce overall emissions would include many modern plants commissioned in the past five to ten years (Davis and Socolow, 2014). CCS retrofits can be an option that preserves the value of these assets while reducing emissions. Furthermore, if electricity demand in China declines in the future due to efficiency and structural changes, retrofitting existing power capacity may have increased attractiveness compared to adding new low-carbon capacity to an oversupplied system.

Other scenarios are foreseeable. In 2014, China developed a scenario for the DDPP in which its emissions would grow until 2030 and decline thereafter (DDPP, 2014). This scenario is shown in Figure 7.

Figure 7 • CO<sub>2</sub> emissions from existing CEC plants compared with IEA WEO scenarios



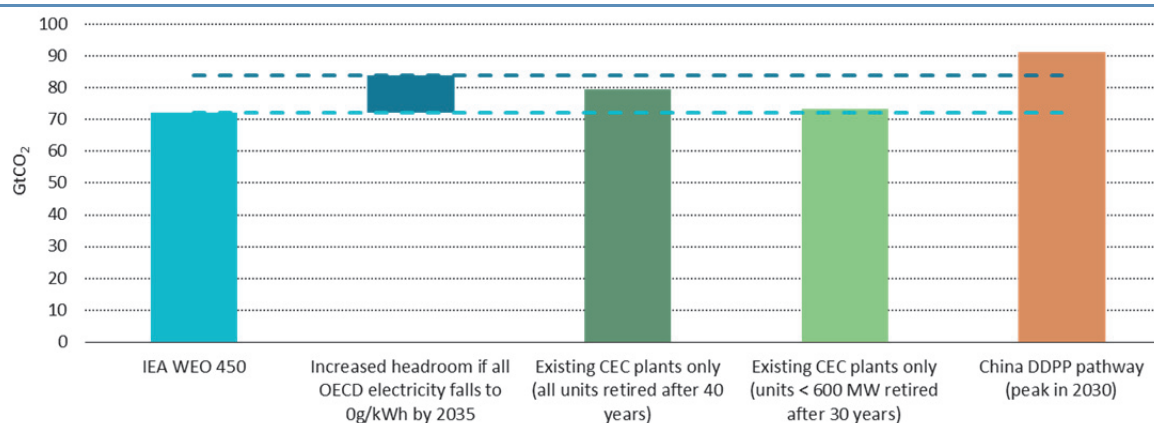
Note: For existing CEC plants no retrofitting of technology to reduce specific emissions is assumed, including CCS. The discrepancy between the DDPP and IEA emissions levels is likely due to the exclusion of Hong Kong and the exclusion of emissions allocated to the provision of heat from electricity generation facilities in the DDPP estimate.

Source: CEC; IEA, 2014; DDPP, 2014.

In the WEO 450 scenario, the emissions from all Chinese electricity generation are lower than the emissions from all existing CEC units over 600 MW if they were operated up to a 40 year lifetime without CCS retrofit (Figure 8). WEO 450 is just one representation of an energy system transition to keep the global average surface temperature rise below 2°C. For example, China's electricity system would be able to emit more CO<sub>2</sub> if other countries took on more of the emissions reduction burden. However, even if all OECD countries reduced the emissions intensity of their

electricity generation to 0 g/kWh between 2020 and 2035 – a monumental and highly improbable undertaking – the additional headroom for the Chinese electricity sector would only be sufficient to support the emissions from existing CEC plants but no emissions from gas-fired plants or new coal plants. Due to the sheer scale of the Chinese electricity sector, meeting a 2°C target requires significant changes in China's power generation mix alongside action elsewhere in the world.

**Figure 8 • CO<sub>2</sub> emissions from Chinese electricity generation under different scenarios, 2015 to 2040**



Note: Increased headroom if all OECD electricity falls to 0g/kWh by 2035 is calculated on the basis of WEO 450 electricity demand and a linear reduction factor from the average emissions intensity of the OECD in WEO 450 in 2020 to 0g/kWh in 2035.

Source: CEC; IEA, 2014, DDPP, 2014.

In the IEA WEO 450 scenario, the retrofit of CCS to coal-fired capacity enables the divergence between the emissions trajectory and the continued use of coal to be reconciled. In this scenario, CCS retrofits are found to be the most cost-effective approach to reducing emissions, especially considering the expectation that unabated coal-fired capacity will continue to be constructed in China in the next decade if not longer. The retrofitting of plants in China in this scenario begins to ramp up around 2025 and by 2035 the installed capacity of CCS-equipped power plants is 249 GW, of which 185 GW are retrofits of plants that were not built with CCS integrated.

## Retrofitting CCS: how and why?

### Key points

*Adding CO<sub>2</sub> capture to a coal-fired power plant can be achieved by adding a capture unit that separates CO<sub>2</sub> from the flue gases before they are released to the atmosphere. The **addition of CO<sub>2</sub> capture may be timed to coincide with other power plant upgrades.***

*After capture, the **CO<sub>2</sub> must be transported to a suitable CO<sub>2</sub> storage site and permanently stored underground.** Transport of CO<sub>2</sub> in pipelines is a known and mature technology. Storage of CO<sub>2</sub> involves the injection of CO<sub>2</sub> into suitable geologic formations that are typically located at about one kilometre or more underground; it also involves the subsequent monitoring of injected CO<sub>2</sub>.*

***Adding CCS to a power plant incurs an operational cost** due to the reduction of efficiency caused by the energy requirements of CO<sub>2</sub> capture, transport and storage. CO<sub>2</sub> capture is responsible for the majority of additional energy requirements, which translate into fuel costs for the power plant operator. The efficiency penalty will depend on the type of CO<sub>2</sub> capture technology used and anticipated technological advances.*

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A coal-fired power plant equipped with CCS can be a source of low carbon electricity that has the advantages of thermal generation plants: high availability all year, responsive to changes in supply and demand, and value-added for indigenous resources. In the future, electricity markets and consumers are likely to place a high value on low carbon electricity and CCS can reduce the emissions from a state-of-the-art hard-coal power plant from around 800 gCO<sub>2</sub>/kWh to around 100 gCO<sub>2</sub>/kWh if 90% of the emissions are captured and stored. For retrofits specifically, the addition of CCS can maintain the value of assets that currently have a high carbon footprint and extend their operational lifetimes to maximise their value. This can be a highly valuable option for managing the emissions from existing fossil-fuel fired power plants, as described in the previous section.

The operator of an existing coal-fired plant has several options available when faced with policies that constrain its continued unabated operation.

- The plant could be retrofitted with CCS – either fully or partially – to extend its lifetime and allow it to continue to be profitable despite regulations on CO<sub>2</sub> emissions.
- The plant could be run for only a small fraction of its available hours per year, which would have associated costs, or retired and replaced with new low-carbon generation capacity. This new capacity could be a new build CCS plant, which would have a longer lifetime than the CCS retrofit and be more efficient, but would require more capital investment and costs for decommissioning of the older plant.
- In some cases, for example where electricity demand is declining, it may be advantageous to retire the plant without replacing it, possibly after a period of operating with a reduced load factor to lower annual emissions. However, in China, electricity demand is not expected to enter a prolonged period of decline in the coming two decades.<sup>5</sup>

<sup>5</sup> In some regions, continued penetration of variable renewable energy electricity supplies could lead to a reduction in the amount of load provided by thermal generators and impose more flexible modes of operation on them. This could have the combined impact of reducing revenue and raising unit costs. The outlook for Chinese power markets would therefore need to be taken into account when considering the economics of coal-fired plants and policies that would support CCS retrofits.

## How is CO<sub>2</sub> capture added to a power plant?

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Adding CO<sub>2</sub> capture to a coal-fired power plant can be achieved by adding a capture unit that separates CO<sub>2</sub> from the flue gases before they are released to the atmosphere. This is known as “post-combustion capture”. The most cost-effective approach today is absorption of CO<sub>2</sub> by amine-based solvents that are regenerated by heating, which liberates the absorbed CO<sub>2</sub> to be compressed for transport. To avoid contamination of the solvent, the flue gas needs first to undergo flue gas desulphurisation (FGD). Chinese standards already require most coal-fired plants to meet a high level of FGD such that meeting the levels required for CO<sub>2</sub> capture should be achievable. Around the world there is a research focus on more advanced ways of capturing CO<sub>2</sub> from coal combustion flue gas, but it is expected that amine solvents will remain the dominant large-scale technology for power plant retrofits for at least the next decade (IEA, 2015d). More detail can be found in Annex 2.

There are two main options for providing a CO<sub>2</sub> capture retrofit with the heat required for solvent regeneration. The first involves taking the heat from the steam turbine, which leads to a reduction in the net power output of the plant. The second is to import heat from another plant, for example a nearby gas-fired combined heat and power (CHP) plant, and avoid the reduction in the net power output of the coal plant. The latter case will incur higher costs, especially if a new CHP plant is constructed, but can deliver higher revenues by avoiding a reduction in electricity output from the retrofitted plant and selling excess electricity from the CHP plant.

This study assumes that in the timeframe to 2030, the most likely approach to retrofitting CCS is post-combustion CO<sub>2</sub> capture using an amine solvent-based system. More specifically, the energy requirements for the CO<sub>2</sub> capture system are met by some of the steam being diverted from the power plant's own steam cycle and some of the electricity diverted from its generators instead of being supplied to the grid. Thus for cost and technical considerations, we assume that retrofitting CCS will reduce (de-rate) the available electricity generating capacity and hence reduce the net efficiency, but maintains similar levels of inputs such as coal and water. However, as described above and in Annex 2, this is not the only option.

While 90% CO<sub>2</sub> capture using post-combustion approaches is often cited, the capture rate can be varied during design and operation. It can be increased above 90% so that emissions fall to 50 gCO<sub>2</sub>/kWh or below, but the marginal cost of capture increases significantly at very high capture rates.<sup>6</sup> On the other hand, it can be cost effective to partially retrofit a coal-fired power plant, for instance by retrofitting half the existing units if the target is to reduce emission only to the level of a natural gas-fired CCGT (NETL, 2015; Zhai, Ou and Rubin, 2015). To achieve an emissions rate of 450 gCO<sub>2</sub>/kWh requires a capture rate of around 60% across the whole plant. The resulting plant would provide a near-term improvement in emissions, but over the longer-term would be likely to be one of the most emissions intensive plants if average emissions fall to below 100 g/kWh and no further retrofit is undertaken.

The addition of CO<sub>2</sub> capture to a power plant may be timed to coincide with other plant upgrades that add FGD or replace the boiler or turbines. These upgrades can extend the life of the plant by several decades. Of the plants currently in operation worldwide that have been retrofitted to improve plant efficiency only, 95% were built between 1955 and 1979, showing that the retrofit has contributed to a prolongation of their lifespan beyond the 40 year average (Purvis, 2014). Plant upgrades were integral to the retrofit of CO<sub>2</sub> capture to Unit 3 of the Boundary Dam<sup>7</sup> power plant in Canada. In contrast, most existing Chinese plants have been built since 2005, and would

<sup>6</sup> Based on the use of today's state-of-the-art retrofit technologies. This statement does not hold true for certain post-combustion retrofit technologies that are under development, such as oxy-fuel combustion.

<sup>7</sup> See more under section “Emerging practical experience from retrofitting”.



be 20 to 30 years old if retrofitted between 2025 and 2035, making the need for upgrades less acute than at Boundary Dam.

Another approach to retrofitting CO<sub>2</sub> capture while upgrading the plant could involve replacing the boiler with a so-called oxy-fuel boiler whereby the coal is combusted in an oxygen-rich environment. This requires a more extensive and expensive upgrade of the plant and energy is required for the production of oxygen from air, but there is a cost saving in CO<sub>2</sub> separation because the resulting flue gas stream is almost 100% CO<sub>2</sub>. While oxy-fuel retrofits cannot be ruled out, the additional retrofit costs and the less developed status of the technology are factors that favour amine solvents.<sup>8</sup>

## CO<sub>2</sub> transport and storage

After capture, a CCS retrofit requires the CO<sub>2</sub> to be transported to suitable locations and permanently stored underground. Transport of large volumes of CO<sub>2</sub> in pipelines is a known and mature technology, with significant experience from more than 6 000 km of CO<sub>2</sub> pipelines in the United States. As mentioned in Box 3, CO<sub>2</sub> is transported 66 km from the Boundary Dam plant in Canada and the same oilfield also receives CO<sub>2</sub> from the Great Plains Synfuel Plant in the United States, 330 km away. There is also experience, albeit limited, with transport of CO<sub>2</sub> using offshore pipelines in the Snøhvit project in Norway. CO<sub>2</sub> is also transported by ship, but in small quantities (IEA, 2013).

Geological storage of CO<sub>2</sub> involves the injection of CO<sub>2</sub> into suitable geologic formations that are typically located one kilometre or more underground; it also involves the subsequent monitoring of injected CO<sub>2</sub>. Suitable geologic formations include saline aquifers, depleted oil and gas fields, oil fields with the potential for CO<sub>2</sub>-EOR and, potentially, coal seams that cannot be mined with potential for enhanced coal-bed methane (ECBM) recovery.<sup>9</sup> Another possibility is to extract and desalinate water that is displaced by CO<sub>2</sub> injection in saline aquifers for use in applications, such as industrial cooling in regions where water availability is scarce. This process has been termed 'enhanced water recovery' (EWR) and is referenced in the 2014 US-China Joint Announcement on Climate Change and Clean Energy Cooperation (White House, 2014).

The fundamental physical processes and engineering aspects of geological storage are well understood, based on decades of laboratory research and modelling; operation of analogous processes (e.g. acid gas injection, natural gas storage, EOR); studies of natural CO<sub>2</sub> accumulations; pilot projects; and currently operating large-scale storage projects (Benson and Cook, 2005; Gale et al., 2015). These experiences have shown not only that CO<sub>2</sub> storage can be undertaken safely – provided proper site selection, planning and operations – but that all storage reservoirs are different and need extensive dedicated characterisation.

A suitable candidate CO<sub>2</sub> storage site (or sites) is one that meets the following criteria:

- Likely to have sufficient capacity to accept the anticipated final volume of CO<sub>2</sub>, for example the volume of CO<sub>2</sub> expected to be captured from a retrofitted power plant over its remaining lifetime or that from multiple sources of CO<sub>2</sub> combined to realise economies of scale.

<sup>8</sup> Amine solvent systems are generally considered to be more flexible as CO<sub>2</sub> capture can be fully or partially bypassed to allow the plant to operate in a non-CCS mode after CCS retrofit. This may be attractive if regulations or CO<sub>2</sub> pricing schemes do not compel CCS for all operating hours of the whole output of the plant, or if bypassing CO<sub>2</sub> capture allows greater operational flexibility at lucrative peak hours. For oxy-fuel plants, achieving this level of flexibility may be more complex but is feasible. For instance, an oxy-fuel boiler could be designed to operate in air-firing mode to avoid the costs of oxygen production, or could direct electricity to bulk oxygen production and storage at times of low electricity demand.

<sup>9</sup> For more information on ECBM, see CCC IA (2015) and GHG IA (2013).

- Has sufficient injectivity to accept the CO<sub>2</sub> stream at the projected supply rates.
- Has containment characteristics that will ensure effective retention of the injected CO<sub>2</sub> over the time-scales established by the regulatory authorities in the applicable jurisdiction.
- Storage of the CO<sub>2</sub> stream at the candidate site(s) does not pose unacceptable risks to other resources, to the environment and human health, and to project developers, owners, and operators.
- Is at a distance from the CO<sub>2</sub> source(s) that is viable in economic and logistical terms.

These criteria emphasise that a level of certainty about the suitability of an identified storage site needs to be reached before a retrofit project can begin. Certainty is achieved through geological surveys and studies of the specific geological formations at the site, which can often take 5 to 10 years. Without good knowledge of the intended CO<sub>2</sub> storage site, the costs of CO<sub>2</sub> transport and storage cannot be calculated and thus the total costs of CCS cannot be accurately estimated.

Besides the geological storage of CO<sub>2</sub>, research has also been directed towards the chemical conversion of CO<sub>2</sub> for production of useful materials or fuels (so-called CO<sub>2</sub> utilisation or mineralisation). In the case of fuels production, the CO<sub>2</sub> is not stored as it is in CCS, but is released to the atmosphere when the fuel is combusted. Because both the capture and conversion of CO<sub>2</sub> require considerable amounts of energy, CO<sub>2</sub> utilisation is unlikely to offer an effective means to reduce the net emissions of a coal-fired power plant (Bennett, Schroeder and McCoy, 2014). In the case of materials production, cost-effective and energy-efficient processes that can use a significant proportion of the CO<sub>2</sub> from a coal-fired power plant are yet to be developed. Nevertheless, research is continuing in this area and technical breakthroughs may allow CO<sub>2</sub> utilisation to complement geological CO<sub>2</sub> storage in the future. Due to the absence of mature CO<sub>2</sub> utilisation or mineralisation options at power plant scale today, only geological storage is considered in this study.

## Costs and benefits

Adding CO<sub>2</sub> capture to a power plant entails capital costs. These capital costs relate to three factors: the amount of CO<sub>2</sub> that needs to be captured, which varies depending on the size and efficiency of the power plant as well as the coal-type; the presence of existing pollution control equipment (e.g. FGD), which is essential for CO<sub>2</sub> capture using amine solvents; and the extent of upgrades to the power plant that are undertaken simultaneously (e.g. upgrading the boiler or turbine). Consequently, different plants can have very different retrofit costs even when considering use of the same technology. A detailed study of five subcritical coal-fired power plants in the United States found that in some cases retrofit costs could be different by as much as 100% (Dillon et al., 2013). In addition, scale factors apply such that retrofitting larger units, or multiple units at once, is cheaper than smaller, single units. More information is contained in Annex 4 about the calculation of CCS retrofit costs.

Adding CCS to a power plant incurs an operational cost due to the reduction of efficiency caused by the energy requirements of CO<sub>2</sub> capture, transport and storage. CO<sub>2</sub> capture is responsible for the overwhelming majority of additional energy requirements, which translate into fuel costs for the power plant operator. The efficiency penalty depends on the type of CO<sub>2</sub> capture technology used. For current, state-of-the-art designs, it is usually considered to be a reduction in the order of nine percentage points. Other operational costs, e.g. solvent purchases, are much lower costs than the impact on fuel purchases per unit of output.

In general, the costs of CO<sub>2</sub> transport and storage have a much lower impact on the costs of electricity than CO<sub>2</sub> capture. IEA analysis indicates that for a coal-fired plant equipped with CCS,

CO<sub>2</sub> transport and storage are responsible for less than 5% of the levelised cost of electricity (LCOE), while CO<sub>2</sub> capture represents two to five times this amount. However, the costs of CO<sub>2</sub> storage rise considerably if the CO<sub>2</sub> needs to be transported over long distances, difficult terrain or offshore.

There are multiple benefits to a CCS retrofit, whose combined value must be weighed against the costs and other investment risks. The primary benefit is the production of low-carbon electricity. Electricity markets around the world are placing increasing value on low-carbon electricity, often giving its producers an advantage over competitors who face more regulation or cannot access higher tariffs. In such markets, producers of low-carbon electricity will be able to run for more hours and may be the only plants that can run at all.

When compared against a new power plant equipped with CCS from the outset, the total capital outlay is much lower. For a retrofit, the capital costs of adding a CO<sub>2</sub> capture system represent the only costs of procuring a low-carbon power plant and this can contribute to a more attractive cost of electricity generation. As stated in the IPCC Special report on CCS, “in cases where the capital cost of the existing plant has been fully or substantially amortised... the [LCOE] of a retrofitted plant with capture (including all new capital requirements) can be comparable to or lower than that of a new plant” (Thambimuthu, Soltanieh and Abanades, 2005). In general, a CCS retrofit will be the more attractive option if additional capacity on the electricity system is not needed and if the alternative to retrofitting is to retire the existing plant.

A second major benefit, therefore, is avoiding the retirement of power plants that still have many years of useful life. Emissions control regulation can threaten existing assets with closure, potentially leading to write-off of capital unless their emissions can be reduced. By extending the lifetime of an existing asset through CCS, investments in new capacity can also be deferred, freeing up capital for investment elsewhere.

A final benefit is the ability to sell CO<sub>2</sub> as a commodity product. The primary customers for CO<sub>2</sub> are likely to be CO<sub>2</sub>-EOR operators but could also include chemical or EWR uses.

Ultimately, a CCS retrofit will make economic sense if its benefits outweigh its costs – i.e. it has a positive net present value (NPV) and its benefits also outweigh the opportunity costs of alternative investments. The extent to which CCS retrofitting occurs will, in the overwhelming majority of cases, depend on whether governments tip the balance of costs and benefits in favour of retrofitting as an emissions-reduction solution. This can be achieved through the use of regulatory measures, market interventions or financial contributions.

It is safe to say that reducing emissions year-on-year from a starting position of a young and dominant coal power fleet will require investment in low carbon electricity generation. These investments can be recovered via revenues from across the electricity system as well as the avoided costs of pollution and climate impacts, including health effects. In the IEA New Policies Scenario outlook exercise, China's electricity generation increases to around 10 000 TWh by 2030, representing a wholesale market worth half a trillion CNY at today's real prices. In the 450 Scenario it is somewhat lower, at around 8 500 TWh, but still 55% higher than today. The cost of successive CCS retrofit projects in China, producing up to 5 TWh per year each and perhaps up to 1 000 TWh in aggregate in 2035, could in theory be spread across the energy system, whose overall emissions intensity will reduce with each addition of low carbon electricity capacity. The first of these projects would be undertaken for technology development purposes, then moving to larger scale decarbonisation projects over time if China pursues this path to reduce emissions from existing power plants.

The exact costs and benefits will depend on the technical characteristics of each plant and other societal aspects, such as opportunities and threats related economic, welfare or employment

effects in a given region. Assessing macroeconomic costs and benefits is beyond the scope of this study, and is a highly complex foresight task,<sup>10</sup> but is nevertheless an aspect that would be worth investigating in future analysis. Aspects such as proximity to CO<sub>2</sub> storage and local electricity market conditions will certainly influence the suitability of Chinese coal-fired plants to be retrofitted with CCS and, in the sections that follow, these and other factors are discussed and evaluated.

**Box 3 • Socio-economic costs and benefits of retrofitting CCS**

In addition to costs and benefits on plant level, wider societal costs and benefits of energy transformation, including via CCS retrofitting, is a very relevant issue. The overall impact of emission reduction on electricity prices/tariffs will depend on various interrelated factors and chosen technologies. While CCS retrofit will increase electricity production costs at an individual plant level, it may well be part of an optimised low-carbon portfolio that minimises any overall electricity tariff increases in the long-run. The impact of CCS retrofitting on the future use of coal and its impact on employment are also important considerations and merit further research. The above issues will require data and analysis, and represent a highly complex foresight task. Assessing macroeconomic costs and benefits is beyond the scope of this study. It is however an aspect that would be worth investigating in future analysis.

## Emerging practical experience from retrofitting

A small number of projects in the world have retrofitted or are retrofitting CO<sub>2</sub> capture to coal-fired power plants. Experience to date is limited and reflects more generally the pace of climate policy progress and thus the slow rate of investment in CCS. However, the three large scale power plants detailed below, as well as future investments in CCS retrofit projects, enhance understanding of retrofitting as an option for low-carbon electricity generation.

### *Boundary Dam*

Boundary Dam Unit 3 is a lignite-fired generating unit in Saskatchewan, Canada that was retrofitted with post-combustion CCS technologies between 2011 and 2014. Unit 3, with an original net generating capacity of 139 MW, was built in 1969 and scheduled for closure in 2013, after almost 45 years in service. The retrofit involved adding an amine-based CO<sub>2</sub> capture plant to remove 90% to 95% of the CO<sub>2</sub> from the flue gas, compress it and inject it into a pipeline to an oil production operation 66 km away. The CO<sub>2</sub> is used there for enhanced oil recovery (CO<sub>2</sub>-EOR) and the power plant operator is paid for the CO<sub>2</sub> it supplies. Boiler modifications were also made the old steam turbine replaced with a new state-of-the-art turbine, and an FGD system added to remove virtually all of the SO<sub>2</sub> from the flue gas. Energy requirements have been minimised by using a combined SO<sub>2</sub>/CO<sub>2</sub> capture system and selective heat integration (Stéphenne, 2014).

After allowing for the energy requirements of the capture plant, net generating capacity for the retrofitted Unit 3 has been reduced to 120 MW, but the refurbishment has extended its life by at least 30 years.

The context for the retrofit at Boundary Dam is the desire of the Saskatchewan province to reduce the CO<sub>2</sub>-intensity of electricity generation, while recognising the ongoing value of lignite as a fuel source. In 2012, Canada introduced a performance standard of 420 g/kWh for new coal-fired electricity generation units and units that have reached the end of their useful life.

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<sup>10</sup> One example of such an analysis, using an input-output methodology, is by Turner (2015).

Saskatchewan has an estimated economically recoverable 300-year supply of lignite coal at current extraction rates and lignite accounts for around 50% of provincial electricity production. The lignite mine that supplies Boundary Dam is just 13 km from the plant and provides a low-cost fuel source compared to alternatives. A commercial demand for CO<sub>2</sub> was readily available at an oilfield in the province, providing a source of revenue to cover part of the costs. These policy and economic conditions enabled the operator of the plant, SaskPower, to absorb the additional costs of the CO<sub>2</sub> capture plant and spread these across ratepayers' bills. In addition, USD 230 million was received as a grant from the Canadian Federal Government.

### ***Petra Nova – Parish project***

Due to begin operation in early 2017, the Petra Nova Parish CO<sub>2</sub> capture project in Texas, USA is under construction. The project is retrofitting post-combustion amine-based CO<sub>2</sub> capture to a 240 MW slipstream of a 610 MW unit located at NRG Energy's Parish sub-bituminous coal-fired power station. This capture unit is designed to capture 1.4 MtCO<sub>2</sub> per year at a capture rate of up to 90%.

The captured CO<sub>2</sub> will be compressed and transported via a 130 km pipeline to the West Ranch oil field, where it is to be injected for EOR at a depth of 1 km to 2 km. The Texas Coastal Ventures and the University of Texas Bureau of Economic Geology are jointly developing a CO<sub>2</sub> monitoring plan for the project.

A key difference between Boundary Dam and the Parish project is that steam and power for the capture unit will be provided by a 75 MW gas-fired cogeneration unit that came online in 2013 (NRG, 2014). As a result, the retrofit will not result in de-rate of the existing asset because steam and power from the base plant will not be redirected for CO<sub>2</sub> capture. Energy from the cogeneration unit that is not needed for CO<sub>2</sub> capture can be sold to the grid at times of high electricity demand or supply shortage, due to the flexibility advantages of a single cycle turbine.

The partners in the joint venture are NRG Energy and JX Nippon Oil & Gas Exploration Company. They have received a grant of USD 167 million from the U.S. government's Clean Coal Power Initiative (CCPI) and, with rest of the funding coming from the project partners, supported by loans of USD 250 million from the Japan Bank for International Cooperation and Mizuho Bank.

The context for the Parish retrofit is the emerging U.S. policy for electricity generation that is making it harder for coal-fired power plants to be built or to continue to operate without the addition of pollution control equipment, including CCS. The Parish plant use over 30 000 tonnes of coal per day from Wyoming's Powder River Basin, which is a low-cost and plentiful fuel source. By taking advantage of U.S. government support and the availability of a local EOR industry, the project partners will gain valuable knowledge about operation of a CCS-equipped facility.

### ***ROAD – Maasvlakte CCS Project***

The Rotterdam Opslag en Afvang Demonstratie (ROAD) CCS retrofit project in the Netherlands is also planning to add post-combustion CO<sub>2</sub> capture to a 250 MW slipstream of a 1 070 MW ultra-supercritical coal-fired power unit that entered operation in 2016. The captured CO<sub>2</sub> would be compressed and transported to a deep offshore storage formation in the North Sea. Some CO<sub>2</sub> may be diverted to nearby greenhouses to diversify revenue.

The CCS project is a joint venture between Uniper Benelux (previously E.ON Benelux) and ENGIE Energie Nederland. Two further envisaged partners of the joint venture are the Port of Rotterdam Authority for CO<sub>2</sub> transport and Oranje-Nassau Energie for CO<sub>2</sub> injection and storage. The ROAD project has been financed by its industrial partners as well as the Dutch government (providers of a EUR 150 million grant) and the European Commission (providers of a EUR 180

million grant). While the project has obtained all necessary permits, at the time of writing the financial close has not been reached. It is hence not clear whether this project will be able to proceed to construction.

The context for the ROAD project is primarily the climate policy in Europe and in the Netherlands. The CCS project was launched at the time of approval of the new coal-fired plant, when European Union Emissions Trading System CO<sub>2</sub> prices were expected to be EUR 30/tCO<sub>2</sub> by 2015, which could counterbalance up to one third of project costs. While these prices have not yet been realised, the outlook for new coal plants in Europe without CCS in the coming decades remains weak. Governments and industry therefore saw a shared interest in investing in commercial scale experience with CCS technologies in the European regulatory and geological context.

### *Pilot scale experience*

In addition to the above large-scale power projects, a number of smaller pilot-scale retrofits up to 30 MW in scale have been operated in several countries in the last two decades, allowing experience to be gained in the development, operation and optimisation of CO<sub>2</sub> capture solutions in the power sector. Such smaller projects have been operated for example in the United States, the UK, Germany and Australia.

China has also operated pilot-scale projects, such as the Huaneng Power's Shidongkou capture project in Shanghai and the Gaobeidian capture project in Beijing.



## Factors that influence CCS retrofits

### Key points

*The decision to retrofit a plant with CCS must take account specific factors relating to the location of the plant and its access to potential storage sites, its design, size and the attractiveness of available alternatives to CCS.*

*In this study, particular attention is paid to the ease with which a plant will be able to access suitable CO<sub>2</sub> storage. A CO<sub>2</sub> capture retrofit requires high confidence that the CO<sub>2</sub> can be transported to be stored to prevent its emission to the atmosphere.*

*Certain features of existing power plants will strongly influence whether a retrofit is likely to make commercial sense on the plant level. These factors include age, size, load factor and type and location of fuel source. In addition, attributes such as cooling type and the steam cycle design will have a key impact on the cost of retrofitting.*

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While it is technically feasible to add post-combustion CO<sub>2</sub> capture to almost any plant at which the necessary onsite space can be acquired (GHG IA, 2011), the decision to retrofit will need to take into account specific factors relating to the location of the plant, its design, size and the attractiveness of available alternatives to CCS. This section looks at the context and characteristics that would make existing Chinese coal-fired power plants good candidates for retrofitting with CCS.

A good candidate for retrofitting is one that meets a basic set of suitability criteria and also has attributes that make the addition of CCS cheaper than for other power plants. At a plant level, commercial considerations, including costs of CO<sub>2</sub> transport and storage, age, size and load factors, will affect retrofit feasibility and costs as well as technical considerations, including steam efficiency and steam cycle design, cooling, pollution controls, and onsite space.

In this study, particular attention is paid to the ease with which a plant will be able to access suitable CO<sub>2</sub> storage. Not only does access to CO<sub>2</sub> storage have a major impact on CCS retrofit costs – the further the CO<sub>2</sub> must be transported or the less suitable the geology, the more expensive it will be – but it is also a factor that may not be under the control of a power plant operator. The exploration and development of CO<sub>2</sub> storage resources requires skills that are commonly associated with the oil and gas sector, and needs to be undertaken in advance of the addition of CO<sub>2</sub> capture equipment. Thus, accounting for access to CO<sub>2</sub> storage is vitally important for assessments of CCS retrofit candidates and it can be used to guide which storage resources are explored today and made available to facilitate future retrofits.

For the purposes of this study, the influential factors have been split into two categories:

- **Suitability criteria** that determine whether a plant is likely to be a candidate for retrofitting. Suitability criteria have been used in this study to identify the subset of existing CEC plants that have the highest potential to be retrofitted. While no specific plant should be completely ruled out for future retrofit based on any single criterion, the suitability criteria are applied in a binary manner to eliminate plants from consideration that are unlikely to be retrofit candidates. These include the critical issue of access to CO<sub>2</sub> storage, as mentioned above.
- **Cost factors** that would not prevent retrofit but would influence the relative attractiveness of the plant as a candidate for retrofitting with CCS. Cost factors have been used to rank plants in the subset of feasible plants in terms of their relative attractiveness for retrofit, and also to explore the relative impacts of different power plant attributes.

The two main categories of criteria are discussed in the following sections. Some additional factors, such as the availability of alternatives, market structure and policy risk, are not covered below but would be considerations in any retrofit decision.

This current study sits somewhere between two previous assessments on CCS retrofitting in China, which concluded that 19% to 58% of China's coal-fired fleet showed good suitability for CCS retrofitting (Box 4). This study evaluates a wider range of criteria, local considerations and unit-level data than the earlier IEA study, and covers a larger number of plants and operational factors than the study by Li.

#### Box 4 • Previous assessments of the suitability of China's coal-fired fleet for CCS retrofit

##### IEA (2012)

As part of an assessment of the global coal-fired power fleet, a limited number of criteria were used to identify which Chinese power plants might be retrofittable. At the time, the installed capacity of Chinese coal-fired plants was 669 GW. At a global level, three cases were evaluated: 600 GW (90% of plants) were found to be younger than 30 years and over 100 MW; 481 GW (72%) were younger than 20 years and over 300 MW; 390 GW (58%) were younger than ten years and over 300 MW. For power plants in this final category, 83% of the plants younger than ten years and over 300 MW were found to be in China. However, it was found that just 34% of Chinese plants under 10 years of age in 2011 had supercritical or ultra-supercritical steam conditions. CO<sub>2</sub> storage opportunities were not evaluated.

Whereas the 2012 analysis looked at age, plant size and steam conditions, it did not – for reasons of achieving global coverage – have sufficiently detailed data on access to CO<sub>2</sub> storage, commercial considerations or other technical parameters.

##### Li (2010)

Seventy-four Chinese pulverised coal power plants (108 GW), each greater than 1 GW and with an available satellite image of the site layout, were evaluated for their potential for a retrofit with CO<sub>2</sub> capture, transport and storage. Factors assessed included geographic location, space on site, plant layout, water restriction, coal supply, efficiency, FGD status and potential access to storage sites. Based on these criteria, retrofitting prospects were evaluated and rated. It was found that 19% (14 plants) appeared to have high retrofit potential, while 46% were unlikely to be suitable for emissions abatement due to space limitations (GHG IA, 2011).

## 1: Suitability criteria

Certain features of existing power plants will strongly influence whether a retrofit is likely to make commercial sense. These factors include access to CO<sub>2</sub> storage, age, size, load factor<sup>11</sup> and type and location of fuel source.

### Access to CO<sub>2</sub> storage

A CO<sub>2</sub> capture retrofit requires high confidence that the CO<sub>2</sub> can be transported to be stored to prevent its emission to the atmosphere. The world's longest CO<sub>2</sub> pipeline is the 800 km Cortez pipeline in Texas, United States. Longer CO<sub>2</sub> pipelines than this are hard to envisage in the next twenty years in which the first phase of CCS projects in China might be developed, especially given that much of China's terrain is mountainous or densely populated. To avoid the possibility of unlimited CO<sub>2</sub> transport distances in this study, which could be politically and technically hard

<sup>11</sup> The ratio of the number of equivalent full load hours a facility operates in a given year to the number of hours in that year. A 70% load factor corresponds to 6 132 full load hours per year. 85% corresponds to 7 446 full load hours per year.

to realise, 800 km is used as an upper limit for distance to suitable CO<sub>2</sub> storage. This maximum is still a long distance that could make a retrofit prohibitively expensive for a power plant far from a suitable CO<sub>2</sub> storage site.

## Age

The current age of power plants is a commercial consideration that can be used to exclude plants that are likely to reach the end of their economic lifetime before a CCS retrofit decision is relevant. To account for the current policy environment in China, we assume that units of 600 MW and above will have an operational lifetime of 40 years, whereas smaller units will have an operational lifetime of 30 years, and units under 300 MW are to be retired by 2025. For this analysis, the retrofit decision for the coal-fleet is assumed to be taken in the period between 2025 and 2035. This is in line with the Chinese ambition to peak CO<sub>2</sub> emissions in 2030 and reflects the fact that from 2025 the gap between emissions from existing coal plants and emission targets begins to open up (Figure 6).

## Size

As discussed earlier, it is a significant commercial consideration that under current Chinese policy smaller units do not appear to have a sustainable future in China. Hence, we assume that units of 600 MW (net) and larger pre-retrofit are candidates for retrofitting, while units under 300 MW (net) pre-retrofit are not. We assume that units between 300 MW and 600 MW are only attractive where there are economies of scale to be gained from a common CO<sub>2</sub> transport and storage solution that serves multiple co-located units at one large plant. For the purposes of this study, we define a large coal-fired plant as one which, if all units were retrofitted with a 90% capture rate, would capture over 10 MtCO<sub>2</sub>/yr (generally around 2.5 GW or greater).

## Load factors

Plants that operate for more hours each year will be able to recover the upfront costs of a CCS retrofit more quickly. Current load factors can provide an indication of whether retrofitted plants would be well-placed to earn revenue to pay off capital expenditure. Load factors for baseload power plants – those that provide a stable and largely constant level of power to the grid – can be around 85% (IEA, 2010). However, in the Chinese system, which is currently oversupplied, average full load hours of coal-fired plants have fallen by 20% in the last decade and many plants operate for 5 000 hours per year or less (i.e. load factors lower than 60%) (CEC, 2015c). Because some of these plants could operate in theory more hours if smaller plants were retired or dispatch was based on short run marginal costs, a suitability threshold of just 50% load factors aims to exclude only those plants that are used just to provide peaking power or are not regularly dispatched for cost or technical reasons.

## Local policy and strategic factors

The commercial opportunity for a CCS retrofit in China will also depend on policies that influence the relative attractiveness of coal use or low-carbon generation in different provinces. Plants located in Northern and Western provinces that use locally mined coal may find more strategic value to continued coal use, including maintenance of local employment and tax revenues. Plants located in highly populated Southern and Eastern provinces, on the other hand, may have better access to cooling water and more pressure to reduce emissions of local pollutants and carbon dioxide. However, the latter provinces are also more likely to have policies to reduce or phase out coal-fired power generation in the next decade, before CCS retrofit decisions will be taken.

The balance between these competing considerations will influence the attractiveness of undertaking CCS retrofits.

At present, the only administrative area with a stated policy to phase out coal use in power generation is Beijing. Thus, only plants in Beijing are excluded as retrofit candidates in this study due to policy factors.

The cost and political impacts of these various local considerations relating to the coal source are difficult to determine, and they have not been included in this study as commercial suitability criteria or cost factors.

### *Space availability*

If there is insufficient space available at the power plant site on which the CO<sub>2</sub> capture facility could be hosted, the plant may be technically unsuitable for CCS retrofit. The total land needed to accommodate a CO<sub>2</sub> capture facility, including compressors, has been estimated in different studies to range from 0.03 to 0.08 hectares per MW retrofitted for units of 300 MW to 600 MW (Florin and Fennell, 2010; GCCSI, 2010; NETL, 2007). Several installations may need to be accommodated depending on the attributes of the power plant, including (DECC, 2009):

- Equipment and associated accessories required for CO<sub>2</sub> capture. Further space may be needed during construction, for storage of equipment and materials and for access to the existing plant.
- Modifications to the boiler and steam turbine island, if necessary.
- Extension and addition of balance of plant systems, as appropriate, to meet the additional requirements of the capture plant, for example cooling water.
- Additional vehicle movement after capture equipment addition, for example for delivery of consumables such as solvents.
- Areas required for the safe storage and handling of potentially hazardous materials such as oxygen, amine based solvents and CO<sub>2</sub>.

In many cases, space could already be constrained due to the addition of SO<sub>2</sub>, NO<sub>x</sub>, and mercury control systems that were not envisaged at the time of plant construction but have since been added. At other sites, space currently occupied by industrial neighbours may become available before the time of retrofit due to scheduled closures or clearances. In China, the rapid expansion of populous and industrial areas has made available space around many power plants more scarce and will likely continue to do so. However, while space availability is a clear suitability criteria, insufficient plant level data prevents it from being considered as such in this study.

## **2: Cost factors**

The cost factors described in this section influence the attractiveness of the retrofit through their impact on the cost of generating electricity with CCS. Some of these factors are the same as the suitability criteria, reflecting the fact that costs related to transport and storage of CO<sub>2</sub>, age, size and load factor vary within the absolute suitability threshold. Other cost factors include: efficiency and steam cycle design and the ease of extracting steam from the turbines at suitable temperature and pressure; cooling type and the ability to expand or add cooling infrastructure to meet the needs of the CO<sub>2</sub> capture facility; and the level of existing pollution controls.

These cost factors are mostly technical and it is noteworthy that technical factors, such as efficiency or cooling type, do not generally preclude a power plant from CCS retrofit. There is, in

most cases, a technical option for upgrading or modifying a plant to make it more suitable for retrofit.

### *Costs of transporting CO<sub>2</sub> and storing it at a storage site*

When considering access to CO<sub>2</sub> storage, the costs of CO<sub>2</sub> transport increase with the length and volume of the pipeline, but are also impacted by factors relating to the routing of the pipeline and the volume of CO<sub>2</sub> carried. Costs of CO<sub>2</sub> storage vary with the depth and injectivity of the storage site, among other things, due to the costs of additional or deeper injection wells. Costs of CO<sub>2</sub> transport comprise pipeline material and construction costs (primarily steel), operational costs (primarily energy), land acquisition and routing costs (including obtaining relevant permissions and any legal fees) and maintenance costs (which will be higher in harsher conditions). The costs of land acquisition, routing and maintenance will be higher if the pipeline crosses provincial borders and inhospitable terrain, such as mountains, lakes, rivers or even populated areas. In addition, pipelines built in densely populated areas need to have a much thicker wall, so the cost for short urban distances can be higher than longer rural distances. Economies of scale mean that larger diameter pipes do not have proportionally higher steel costs and have similar costs for land acquisition and routing

For plants that meet the criteria for access to CO<sub>2</sub> storage, the costs of CO<sub>2</sub> transport might be outweighed by access to a distant but ideal site that has low CO<sub>2</sub> storage costs. To take both considerations into account, the combined cost of CO<sub>2</sub> transport and storage are used in this study when assessing access to CO<sub>2</sub> storage.

### *Costs relating to age, size and load factor*

In the case of age, younger plants are generally less costly to retrofit per MW. They have a longer remaining lifetime over which to pay off capital costs of CCS retrofits. In addition, as plants get older, the necessary upgrades to be undertaken alongside the retrofit of CO<sub>2</sub> capture can increase in number and expense, and components that are not upgraded during the retrofit may pose a higher risk of failure or non-compliance during their remaining years of operation. In the Chinese context, minimising costs and maximising benefits for the total electricity system would likely be achieved by retrofitting CCS to the youngest plants, all other things being equal.<sup>12</sup>

In the case of size, larger units also offer economies of scale as the unit cost of CO<sub>2</sub> capture, transport and storage decrease with increasing design capacity. This is, in part, because capital costs of equipment such as pipes and process vessels do not scale linearly with capacity, but also because costs of planning, construction and mobilisation are generally fixed. CCS retrofit projects at a small number of large plants would be more cost-effective than a large number of small plants, all else being equal. However, there is no clear cut-off for unit size that would make it economically unsuitable for retrofit, as the impact of size on retrofit costs can be outweighed by the impact of other factors – such as proximity to storage. Load factors influence costs by impacting the amount of electricity generated each year and therefore the time over which the retrofit investment can be paid off.

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<sup>12</sup> Note: From the perspective of a private asset owner, this generalization may not always hold true, especially if the main alternative to retrofitting with CCS is continued unabated operation. A study of power plants in the United States concluded that those between twenty and forty years old are the best candidates because by this age the capital expenditure is largely amortised but they are not so old that extensive modifications are necessary (Zhai, Ou and Rubin, 2015). In such a market context, the extent to which the original coal plant is amortised is important because it affects the ongoing cost of capital and therefore the LCOE of electricity after retrofit.

## Efficiency and steam cycle design

No plant is technically too inefficient to retrofit, but retrofitting costs will depend on any necessary modifications to the steam cycle or upgrades to be undertaken at the time of CCS retrofit. Upgrades would be more likely for less efficient units, and retrofitting some young and relatively inefficient plants could reduce CO<sub>2</sub> emissions by a very large amount if they would otherwise continue to operate without CCS and with low efficiency.

The design of the steam cycle impacts retrofit costs. The steam that is used for regeneration of the amine solvent, and release of the CO<sub>2</sub>, can be taken from two sources: the steam turbines or a separate local source, such as a gas-fired CHP plant. The former approach de-rates (reduces) the total power output of the plant, and its future revenue, but has lower up-front costs. The latter option maintains the existing output of the plant but requires construction of an additional adjacent plant. If steam is taken from the existing turbines, the best technical candidates for compatibility with a range of amine solvents are those with a crossover pressure between the low pressure and intermediate pressure turbine cylinders of around 4 to 5 bar (Lucquiaud et al., 2009).

Supercritical and ultra-supercritical power plants are better candidates for retrofitting because the resulting CCS-equipped facilities will have higher efficiencies and therefore lower marginal costs. Plants with design efficiency of over 41% could realistically achieve efficiency of 32% when equipped with CO<sub>2</sub> capture, which is equal to the average global operational efficiency of coal-fired power plants without CCS today. However, many Chinese subcritical plants (with efficiencies below 40%) have pressures of 10 to 12 bar and energy would be lost in downgrading the pressure.<sup>13</sup> For example, a 600 MW subcritical unit with 35% efficiency would have an efficiency around 26% and output of 440 MW after retrofitting with amine CO<sub>2</sub> capture using steam extraction from the turbines. The resulting smaller plant would have high marginal generation costs, raising serious questions about its long-term viability in the electricity market. Thus, the regular dispatch of the unit would likely need to be guaranteed contractually or ensured through market interventions designed to reduce CO<sub>2</sub> emissions.

In China, any requirements to supply heat to local users may affect the ability to retrofit CCS. It is anticipated that 28% of China's coal-fired power plants will be considered to be CHP by 2020, i.e. they will supply excess steam to industrial and residential sites via local pipeline networks. Investments in equipment for the exploitation of excess heat for CHP in the short-term may reduce the availability of steam for CO<sub>2</sub> capture in the longer-term.

## Cooling type

The way in which cooling is provided to a CCS-equipped plant can determine retrofit costs. However, if the heat for amine-based CO<sub>2</sub> capture is extracted from the existing steam turbine, then additional cooling requirements are modest, around 10% to 35%. This is because the energy input remains constant, but the plant output is decreased. Process water is required for quenching and transporting the solvent but these are usually small compared to cooling water requirements and can be recycled (NETL, 2008).

If the existing cooling system is insufficient to supply the additional cooling requirements, open cooling, followed by closed cooling have the lowest costs. If there is not enough water available locally, this does not prevent CCS retrofitting as water constraints can be overcome by using dry

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<sup>13</sup> This can be partly compensated by addition of a backpressure turbine during the retrofit, which would raise the total retrofit costs. Such a modification is assumed in the cost estimations in this study, described below.



cooling.<sup>14</sup> Dry cooling, also called air cooling, does not significantly increase water needs for but is more expensive.<sup>15</sup> Plants using dry cooling to cool the CO<sub>2</sub> capture system have a higher absolute energy penalty and therefore higher marginal costs. Nevertheless, coal-fired power plants in China are routinely built with dry cooling in areas where access to cooling water is limited. This indicates that the costs associated with using dry cooling could be manageable in many cases.

### **Pollution controls**

Amine-based solvents for CO<sub>2</sub> capture cannot tolerate contamination by SO<sub>2</sub>, which must be almost completely removed from power plant flue gas before entering the capture system. A full CCS retrofit (i.e. one that processes all of the flue gas from the power plant) using amine solvents for CO<sub>2</sub> capture would therefore almost eliminate SO<sub>2</sub> emissions, and would likely also reduce NO<sub>x</sub> and particulate emissions at a plant level in a retrofit case (Koornneef et al., 2010). Because it is possible and necessary to add FGD at the time of retrofit to plants that do not already have it, this introduces additional costs.

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<sup>14</sup> Furthermore, under any climate change mitigation scenario in which CCS is widely deployed, there will likely be a reduction in total thermal power generation in a given region and thus lower total water demand, potentially making more water available to CCS-equipped plants.

<sup>15</sup> The cost of dry cooling in China has been reported to be around USD 40 000 per MW of output from a coal-fired plant built in 2007 (Li, 2010).

# Assessment of the CCS retrofit opportunity for the Chinese coal-fired fleet

## Key points

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*At least 310 GW (55%) of existing coal fleet appears suitable for the retrofit of CCS, after application of a strict set of basic criteria. The results indicate that **plant size and access to CO<sub>2</sub> storage criteria have the most profound effect on suitability** for retrofit.*

*Based on the analysis undertaken, altogether **513 GW (92%) of China's existing coal-fired power capacity has access to a suitable storage option**, with 385 GW within a radius of 250 km or less.*

*The **310 GW of CEC units identified as potentially suitable to be retrofitted with CCS** will not be equally attractive for retrofitting as they will vary in terms of costs and local market, policy and other conditions. This analysis indicates that the 100 GW that are the most attractive retrofit candidates have additional electricity production costs of CNY 168/MWh or lower.*

The analysis of CEC plants for their readiness for retrofit has been undertaken in two phases. Firstly, the **suitability criteria** described in the previous section (Table 2) have been used to focus the study on a set of existing power plant units that appear to be potential candidates for retrofitting with CCS in China. Recall that space availability and fuel use issues have not been considered in this analysis.

Following this, retrofit costs were evaluated to shed light on how the various **cost factors** influence the relative attractiveness of the candidate units for retrofitting. The analysis has been undertaken unit-by-unit rather than plant-by-plant. This is because each plant can contain multiple units of different ages, efficiencies and sizes. Total plant characteristics are, however, accounted for as part of the size consideration.

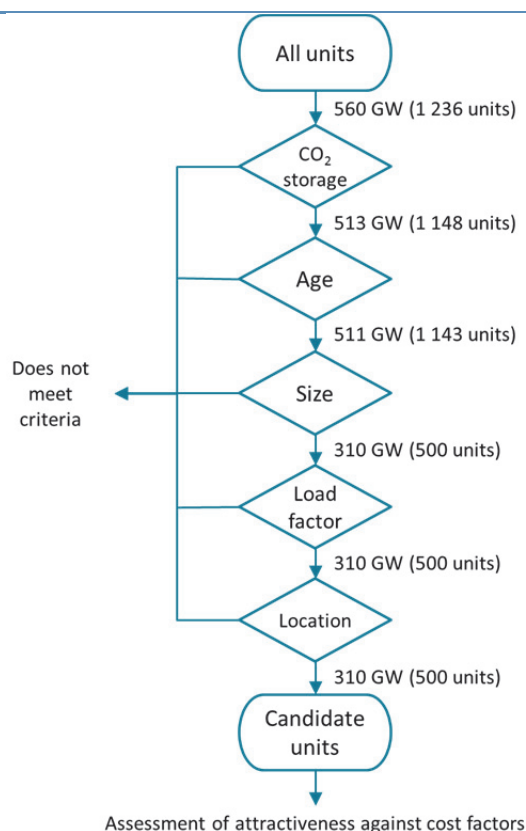
**Table 2 • Suitability assessment factors for retrofit of CCS to existing coal-fired units in China**

Factor	Suitability criteria
Age	≤40 years old in 2035
Size	≥600 MW, or ≥300 MW and at a plant that could in total potentially capture ≥10 MtCO <sub>2</sub> /yr
Load factor	≥50%
Location	Not in a province with a policy to phase out coal completely
Access to CO <sub>2</sub> storage	≤800 km

## Phase 1: Identification of potentially suitable retrofit candidates

Data on 1 236 coal-fired units from 478 separate CEC plants were assessed against the suitability criteria. This data was provided by CEC. The results indicate that at least 310 GW (55%) of CEC member companies existing coal fleet appears suitable for the retrofit of CCS after application of a strict set of basic criteria. (Figure 9 and Table 3).<sup>16</sup>

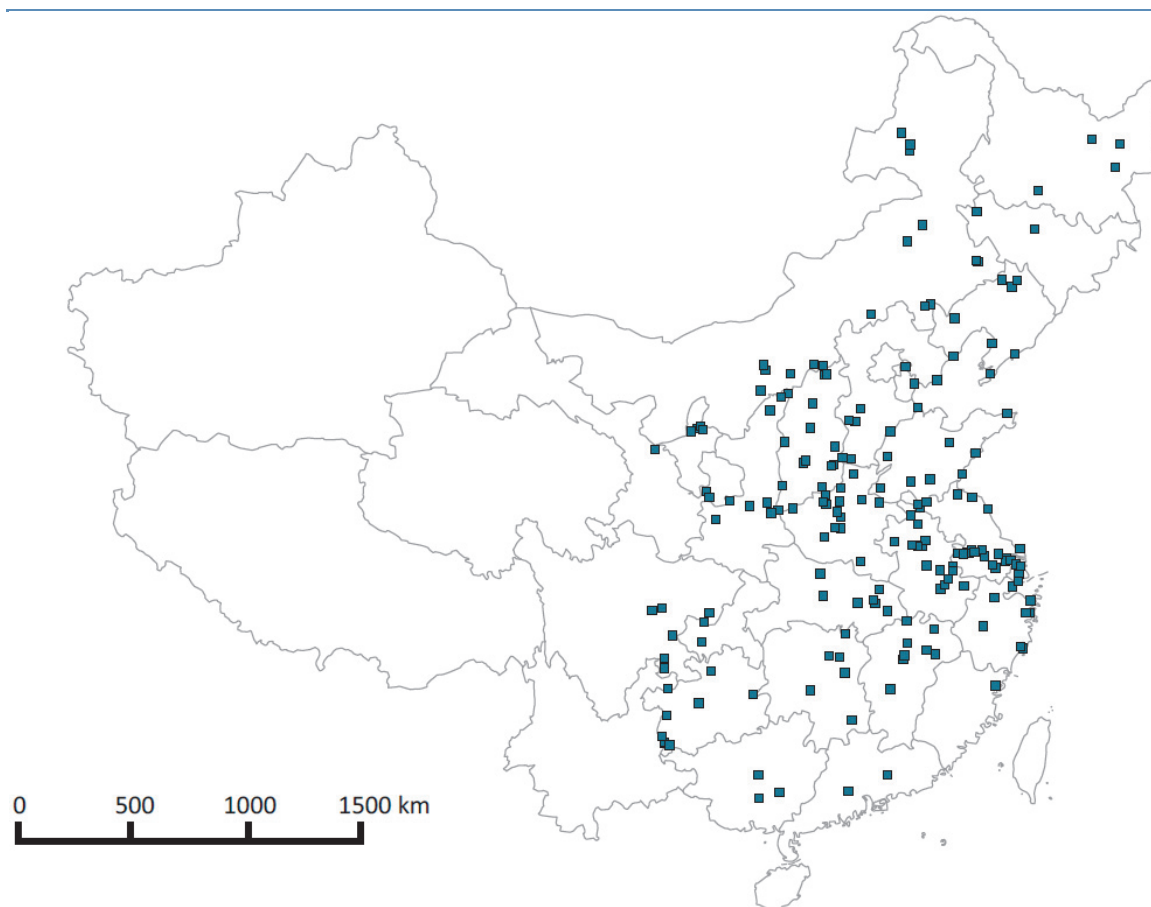
<sup>16</sup> The criteria and the results presented below reflect data availability – for example, because plant-level data about on-site space and specific technical characteristics were unavailable.

**Figure 9 • Flow diagram showing the results of applying suitability criteria****Table 3 • Summary of the results according to suitability criteria**

	Number of units	GW	Proportion of all GW
All CEC units	1 236	560	100%
Units that meet individual suitability criteria:			
Access to CO <sub>2</sub> storage	1 148	513	91.5%
Age	1 231	559	99.7%
Size	556	348	62.1%
Load factor	1 234	560	99.9%
Location	1 230	559	99.8%
Units that meet all suitability criteria	500	310	55.4%

The results indicate that the size and access to CO<sub>2</sub> storage criteria have the most profound effect on suitability for retrofit. The 500 separate units are located at 196 different plants. These 500 units are mostly located in the East and South of China (Figure 10). Units in western provinces are all excluded by the size criterion and not by the proximity to storage or other criteria.

Figure 10 • Distribution of coal-fired units in China that meet all retrofit suitability criteria



Note: This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Source: IEA analysis.

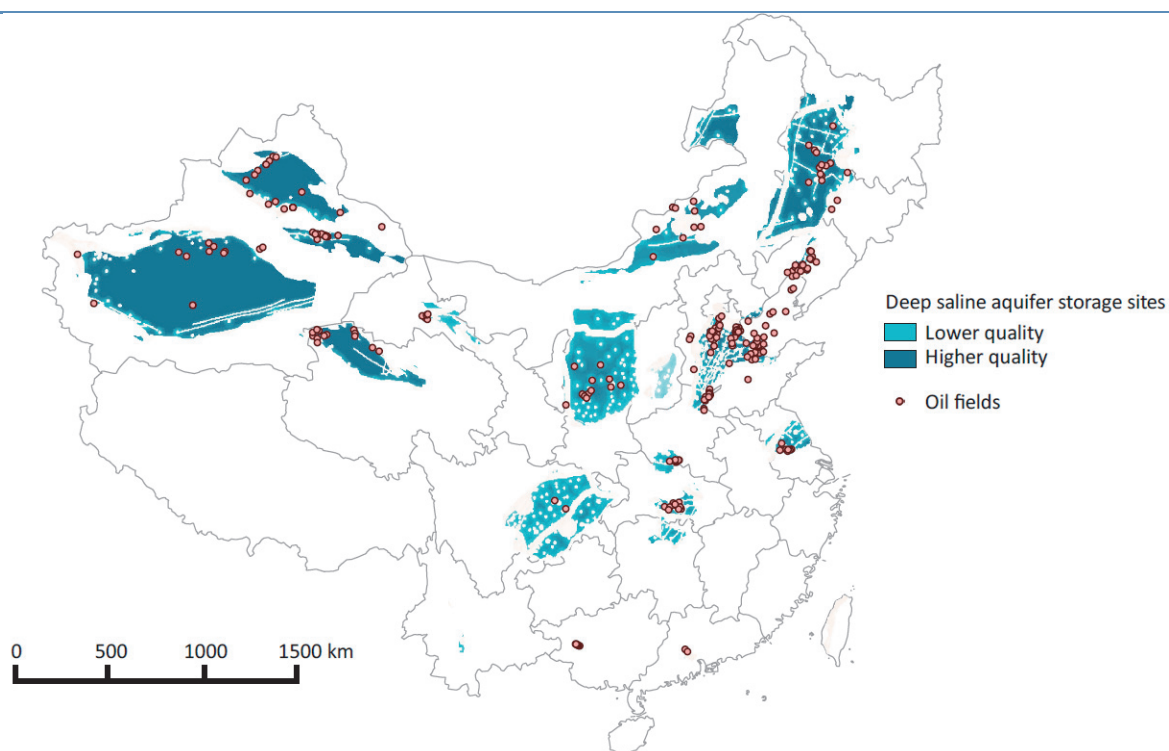
## Description of phase 1 results

### Access to CO<sub>2</sub> storage

To ascertain whether existing coal-fired power plants in China are in good proximity to CO<sub>2</sub> storage sites, each plant location was compared with a Chinese geological database following the methodology described in Annex 5. In China, as in most countries, saline aquifers and oilfields that are suitable for CO<sub>2</sub> storage are distributed unevenly (Figure 11).

For each combination of power plant unit and possible storage site, the combined cost of CO<sub>2</sub> transport and storage was calculated. By using this metric for comparison, it is possible to account for the possible desirability of transporting CO<sub>2</sub> further to reach a CO<sub>2</sub> storage site with a more favourable geology. The output was then used to assess whether each unit has access to a suitable CO<sub>2</sub> storage site and which is its lowest cost option. The analysis assumes that each unit is retrofitted in isolation and has access to its lowest cost site without any competition with CO<sub>2</sub> from other CO<sub>2</sub> capture facilities. 512.6 GW (92%) of CEC capacity has access to a suitable storage option within 800 km. This is a total of 1 148 units.

Figure 11 • Distribution of CO<sub>2</sub> storage resources in China



Note: This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

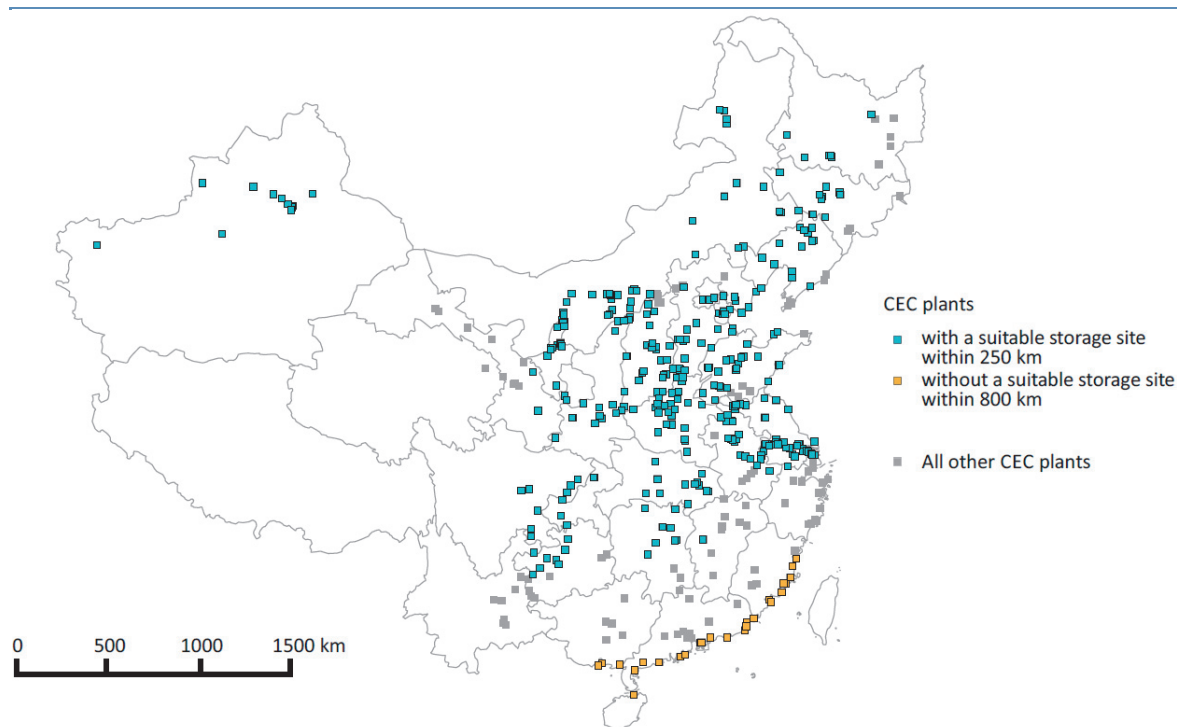
Source: Chinese Academy of Sciences (CAS).

The plants that do not have access to CO<sub>2</sub> storage within 800 km are mostly located Guangdong and Fujian provinces (Figure 12). If, on the other hand, 250 km is taken as an example of a lower threshold for CO<sub>2</sub> transport, possibly to reflect political or societal preferences, it is found that 865 units, 385 GW (69%) of CEC capacity has access to a suitable storage option within 250 km.<sup>17</sup> The plants that do have access to CO<sub>2</sub> storage within 250 km are mostly located in North China, South Central China and East China.

These results indicate that access to CO<sub>2</sub> storage is unlikely to be a factor that prevents retrofitting of CCS to installed coal-fired units in China. However, the costs of transport and storage vary depending on both transport distance and features of the storage site, such as injectivity. For 55% of the units with access to a suitable CO<sub>2</sub> storage site within 800 km, the costs of CO<sub>2</sub> transport and storage are USD 20/tCO<sub>2</sub> or lower, while just 5% have very high transport and storage costs above USD 100/tCO<sub>2</sub>.

Of course, as more information becomes available about the saline aquifer storage resource and the costs of storage in China, the results presented here may be revised. If the storage resource is of a lower quality than anticipated, only a major downwards revision (well above 50%) for key storage regions would impact these results. On the other hand, they could improve as a result of the availability of CO<sub>2</sub> storage via CO<sub>2</sub>-EOR or in offshore saline aquifers, neither of which have been included in this analysis.

<sup>17</sup> 250 km is used as the upper limit in China in work by Dahowski et al. (2013).

Figure 12 • CEC plants with suitable CO<sub>2</sub> storage within 250 km (blue) and 800 km (yellow)

Note: This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Source: IEA analysis.

Offshore storage is likely to be a closer option for units in the South East of China, but transport and storage costs may nevertheless be higher due to the more difficult conditions. As an indication of possible cost increases, offshore CO<sub>2</sub> storage in Europe is estimated to cost 30% to 300% that of onshore storage, depending on the site and the amount of prior knowledge of the geology (ZEP, 2011). Nonetheless, as the extent of offshore storage becomes better understood, the prospects for some southern plants without good access to onshore storage may improve. Work is ongoing in Guangdong province to better characterise and quantify the offshore CO<sub>2</sub> storage potential in China. This includes collaboration between Chinese and UK scientists, as well as the China National Offshore Oil Corporation (CNOOC), on projects in Guangdong is increasing understanding (Zhou, 2013; GDCCUS, 2014).

While CO<sub>2</sub>-EOR has been estimated to offer over 100 MtCO<sub>2</sub>/yr of CO<sub>2</sub> storage resource (Dahowski et al., 2013; Wei et al., 2015) for China, its exploitation remains subject to the evolution of the oil price and the development of indigenous expertise and supply chains for CO<sub>2</sub>-EOR (Han, 1999; Zhang, 2015). However, because the demand for CO<sub>2</sub> supply for EOR projects tends to decline over the life of an EOR project and, at peak, may be less than the amount of CO<sub>2</sub> supplied by a large power plant, a network of CO<sub>2</sub>-EOR operations or a combination with aquifer storage would likely be required.

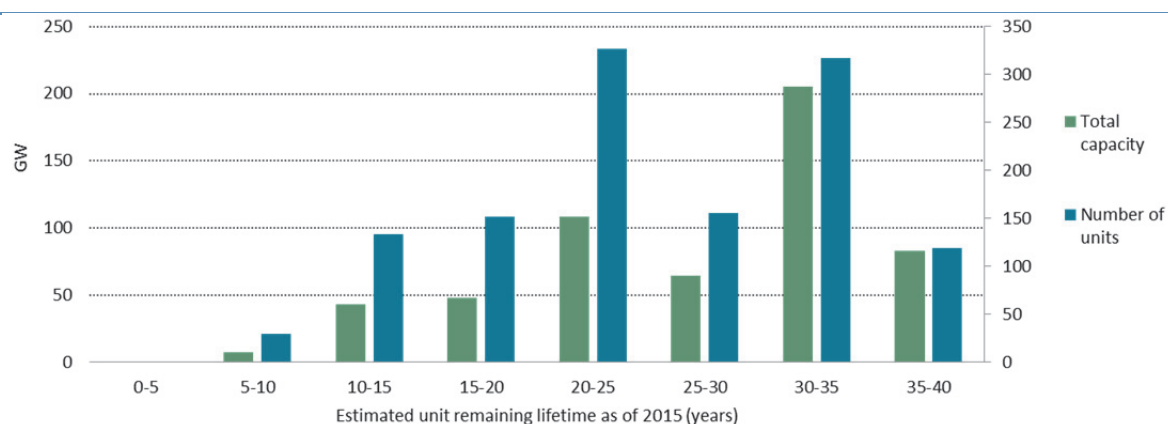
## Age

On the basis of our assumptions about the impact of Chinese policy, 469 GW (84%) of CEC capacity would have at least ten years of lifetime remaining in 2025 and would reach the end of its design life after 2035 (Figure 13). This is a total of 944 units. Recall that this assumes that in the current Chinese policy context, units of 600 MW and above can be expected have an



operational lifetime of 40 years, whereas smaller units are more likely to have an operational lifetime of 30 years, and units under 300 MW are to be retired by 2025.

**Figure 13 • Estimated distribution of remaining years of operation of CEC units as of 2015**



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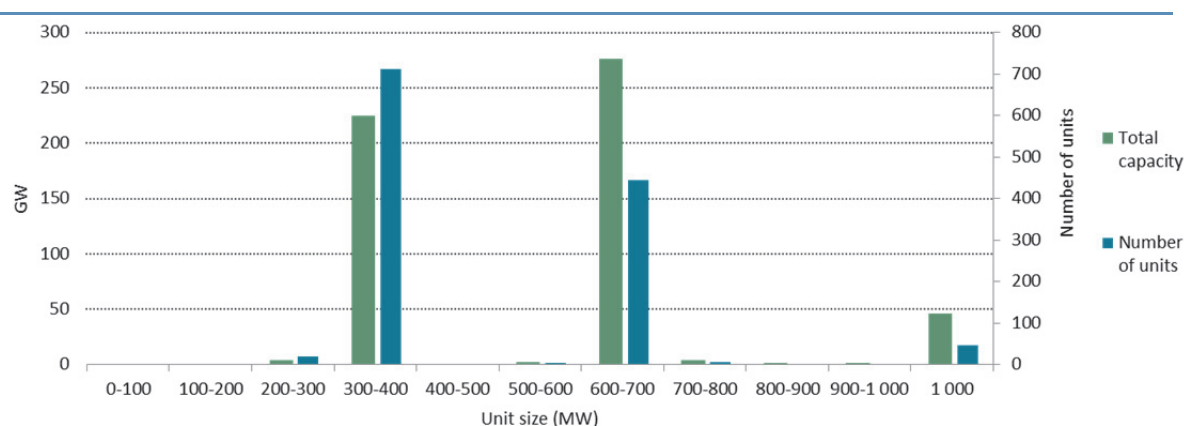
Note: A 40 year operational lifetime is assumed for units of 600 MW or above. A 30 year lifetime is assumed for units of 300 MW to 600 MW. Units of under 300 MW are assumed to be retired in 2025. This would not account for any significant upgrades in the intervening period to prolong lifetimes.

Source: CEC.

### Unit size

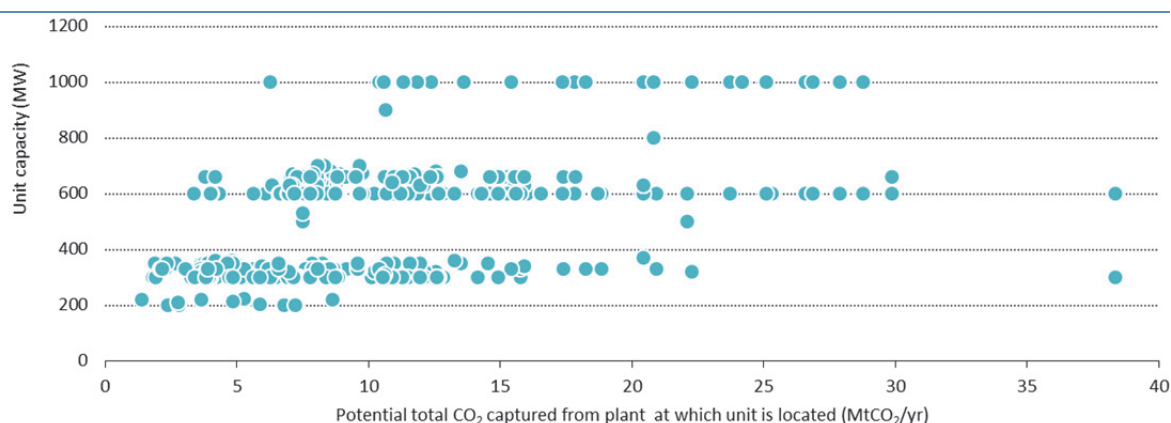
The total 560 GW of CEC capacity in the data set is mainly split between three size ranges (Figure 14). This shows that Chinese coal-fired unit sizes are quite standardised and that the majority of units are smaller than 600 MW. In terms of the overall emissions rates of the plants, larger units are more likely to be found at plants that could capture more than 10 MtCO<sub>2</sub>/yr if the full plant was retrofitted with a 90% capture rate (Figure 14). Among all CEC units, 223.6 GW are located at plants whose captured emissions would pass this threshold.

**Figure 14 • Distribution of capacities of CEC units**



Note: Ranges are not inclusive of the higher value in the range displayed on the axis.

Source: CEC.

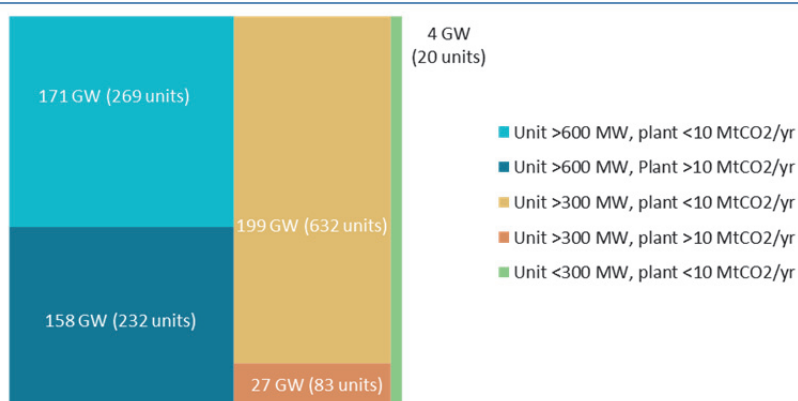
Figure 15 • Relationship between CEC unit sizes and potential total CO<sub>2</sub> captured from their host plants

Notes: Potential rates of CO<sub>2</sub> capture calculated on the basis of current load factors, design efficiencies, design coal types, a 90% CO<sub>2</sub> capture rate and an efficiency penalty of nine percentage points.

Source: CEC.

In terms of the suitability criteria, 329 GW has a unit size of 600 MW or above, while 27 GW has a unit size between 300 MW and 600 MW and is located a plant with a potential total capture rate of 10 MtCO<sub>2</sub>/y or greater (Figure 16). Thus, 357 GW (64%) of CEC plants meet the size suitability criteria.

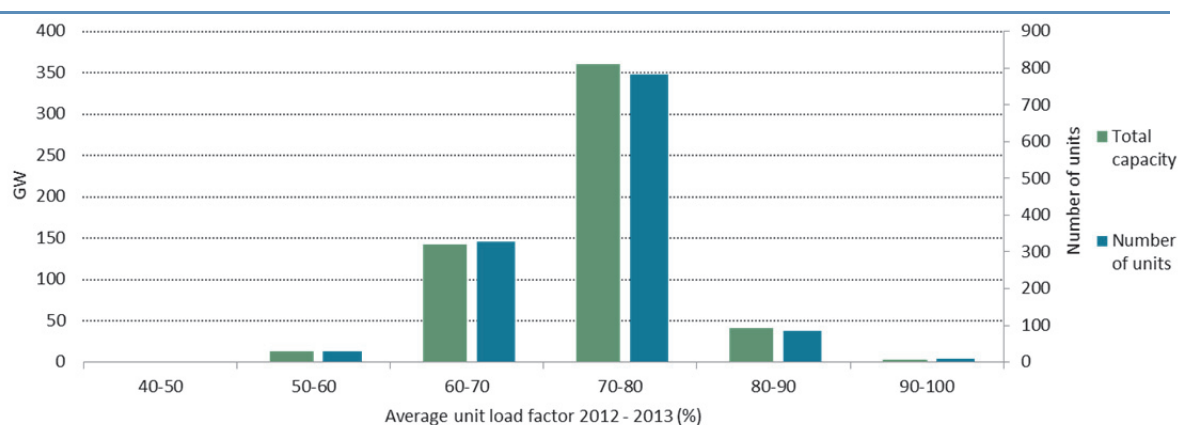
Figure 16 • Proportions of the total number of CEC units meeting the defined size thresholds



### Load factor

In 2012 and 2013, average load factors of CEC coal-fired units varied between 45% and 100% (Figure 17).<sup>18</sup> 560 GW (99%) of CEC capacity had an average load factor of 50% or over in these two years. This is a total of 1 234 units. While load factors of units may change between today and when a decision to retrofit CCS is taken, recent data provides a useful indication of a unit's role and value. Just 11 GW had an average load factor of 85% or over.

<sup>18</sup> 100% load factors were reported when units operated on average at output levels higher than their nameplate capacities.

**Figure 17 • Average load factors of CEC units in 2012 and 2013**

Source: CEC.

There is a geographical element to the distribution of load factors. Average load factors are highest in East China (74%) and lowest in Northeast China (66%) (Table 4). However, because load factors are partly determined by overcapacity, which may decrease over the next two decades, ruling out retrofits in any regions on this basis seems premature.

**Table 4 • Average load factors of CEC coal-fired units in 2012-2013 by region**

Region	Provinces and autonomous regions	Average load factors
North China	Beijing, Inner Mongolia, Hebei, Shanxi, Tianjin	73%
Northeast China	Heilongjiang, Jilin, Liaoning	66%
East China	Anhui, Fujian, Jiangsu, Jiangxi, Shandong, Shanghai, Zhejiang	75%
South Central China	Guangdong, Guangxi Zhuang, Hainan, Henan, Hong Kong, Hubei, Hunan, Macau	72%
Southwest China	Chongqing, Guizhou, Sichuan, Tibet, Yunnan	72%
Northwest China	Gansu, Ningxia Hui, Qinghai, Shaanxi, Xinjiang	73%

Source: CEC.

### Local policy and strategic factors

In 2013, before action was taken to phase out coal fired power from Beijing, 1.3 GW (0.2%) of CEC capacity was located in Beijing. This is a total of just 6 units.

## Phase 2: looking at relative retrofit costs

The 310 GW of CEC units identified as potentially suitable to be retrofitted with CCS will not be equally attractive for retrofitting as they will vary in terms of costs and local market, policy and other conditions. The primary influences on costs are the cost factors identified earlier. In this section, cost estimates are presented and the influences of the different cost factors are explored. Annex 3 presents further information on the distribution among CEC plants of cost factors such as efficiency, cooling type and pollution controls.

It is to be further stressed that this study assumes that retrofitting reduces the available electricity generating capacity (de-rates the thermal efficiency), as a proportion of the steam is required to run the capture process and is no longer available to generate electricity.

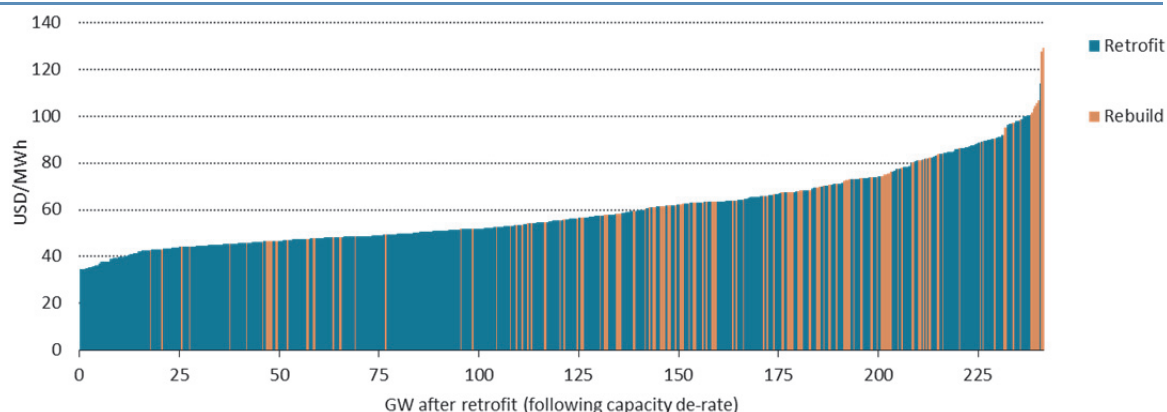
For the purposes of this study it means that the above-mentioned 310 GW of gross generating capacity deemed suitable for retrofitting will be reduced to roughly 240 GW of remaining net electricity generating capacity. In the following cost discussion, the electricity generating costs are calculated on the net / remaining capacity.

## A Levelised Additional Cost of Electricity (LACOE) curve

A decision to retrofit any one of the candidate units would depend on a variety of factors that will influence the value of such an investment. Costs and benefits will be carefully evaluated in the local context and it is not possible today to say with any certainty which CEC units are the most attractive to retrofit and what the profitability of each will be. However, it is possible to generate an estimate of how much extra it will cost to generate a unit of electricity after a unit has been retrofitted. We have termed this metric the “Levelised Additional Cost of Electricity” (LACOE) and believe it can be a useful tool to guide decision-making about CCS retrofits.

The LACOE accounts for the levelised cost of capital for the capture and compression systems, operations and maintenance costs, fuel costs, and CO<sub>2</sub> transport and storage costs. The performance and capital cost estimates used here are based on today's state-of-the-art post-combustion solvent capture technology. Estimates of engineering and procurement costs were extracted from recent studies for CO<sub>2</sub> capture plants, adjusted to fit the known parameters for retrofit of CEC plants, and then appropriate project contingencies and owner's costs have been added to arrive at overnight capital costs. Transport and storage costs are those for the lowest-cost storage site, as identified in the earlier analysis. The resulting cost curve reflects the best estimates of U.S. capital and fixed operational costs (Figure 18). Annex 4 provides details of the cost calculations and underlying assumptions.

Figure 18 • Levelised additional electricity costs for CEC units suitable for retrofitting



Note: The year 2030 has been chosen as the decision year for the retrofit investment, which is the mid-point of the period 2025 to 2035.

Source: IEA analysis.

For each plant, the lower cost of two different options is presented. One option is the retrofit of the existing plant in 2030 with minimal modifications of the underlying asset. The second option includes rebuild of the existing asset to provide it with a further 40 years of life using best available boiler and turbine upgrade technologies. Results show that the rebuild option is more attractive for older plants, with 29 years as the average age of rebuilds at the time of the retrofit investment decision and 21 years as the average age of retrofits. This reflects the value of extending the unit lifetime. While the capital costs are higher for a rebuild, a life extension means

that they can be paid off over a much longer time period if the existing plant is nearing the end of its economic life.

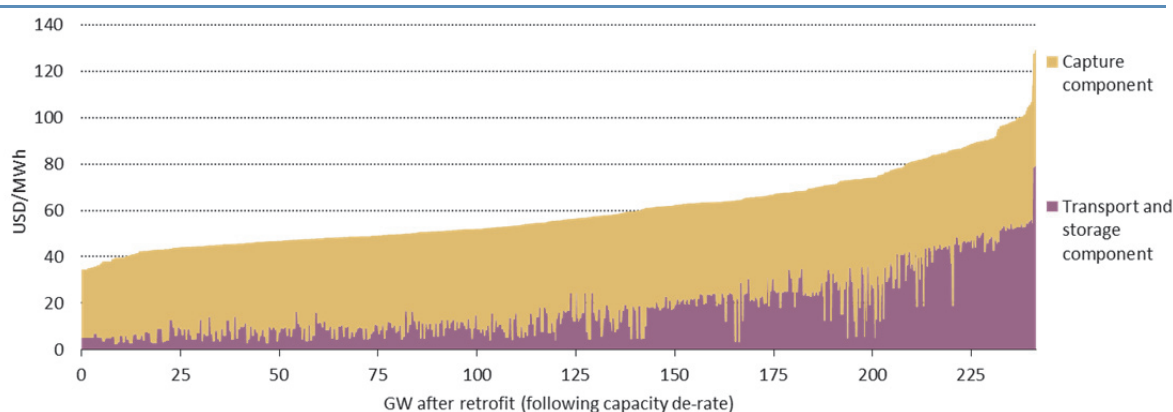
The LACOE can be considered as representative of the premium that an operator would need to receive per unit of electricity generated in order to recover the additional costs of producing low-carbon electricity instead of electricity with high emissions of CO<sub>2</sub>. In practice, the effective value that would need to be offered to generators to induce the retrofit of CCS via a feed-in-tariff or similar system would be influenced by factors including: projected load factors, CO<sub>2</sub> pricing, interactions with the electricity market and the alternative to retrofitting with CCS. The decision of whether or not to retrofit or rebuild an existing asset will be dependent on whether continuing to operate without CCS is a realistic alternative for the remainder of the plant's life.<sup>19</sup> If an operator is faced with a decision to retrofit CCS or retire a unit that has not yet reached the end of its economic life, the premium required to incentivise the retrofit might be lower.

Costs vary between 34 and 129 USD/MWh for the remaining net 240 GW of post-retrofit capacity. Out of this, the estimated additional cost is 49 USD/MWh or less for 78 GW of capacity.

It is likely that costs in 2025 to 2035 will be lower than those quoted here because projects around the world will continue to deliver improvements in CO<sub>2</sub> capture technology and reduce the risk-premium faced by first-movers. In China, if post-combustion CCS is applied to coal-fired power plants in a coordinated, progressive deployment, the resulting standardisation, economies of scale and locally-relevant experience would likely reduce costs considerably as retrofitting progressed. However, the impact of these factors in the coming decade cannot be reliably foreseen and, thus, have not been considered in this study.

For plants at the lower end of the LACOE curve, reductions in CO<sub>2</sub> capture costs would have a proportionally large impact on total costs (Figure 19). For the units that appear most attractive for CCS retrofits, CO<sub>2</sub> transport and storage is a minor cost component. However, at the higher end of the curve, the capture of LACOE is lower and CO<sub>2</sub> transport and storage costs are much higher in both absolute and proportional terms. Thus, long distances from a low-cost storage option may be the factor that would exclude many units from being among the most attractive candidates for retrofitting. This shows the sensitivity of total costs to the trade-off between different CO<sub>2</sub> storage options. Higher transport and storage costs can be acceptable if the capture component is lower, and vice versa.

**Figure 19 • LACOE: CO<sub>2</sub> capture and CO<sub>2</sub> transport and storage components**



Source: IEA analysis.

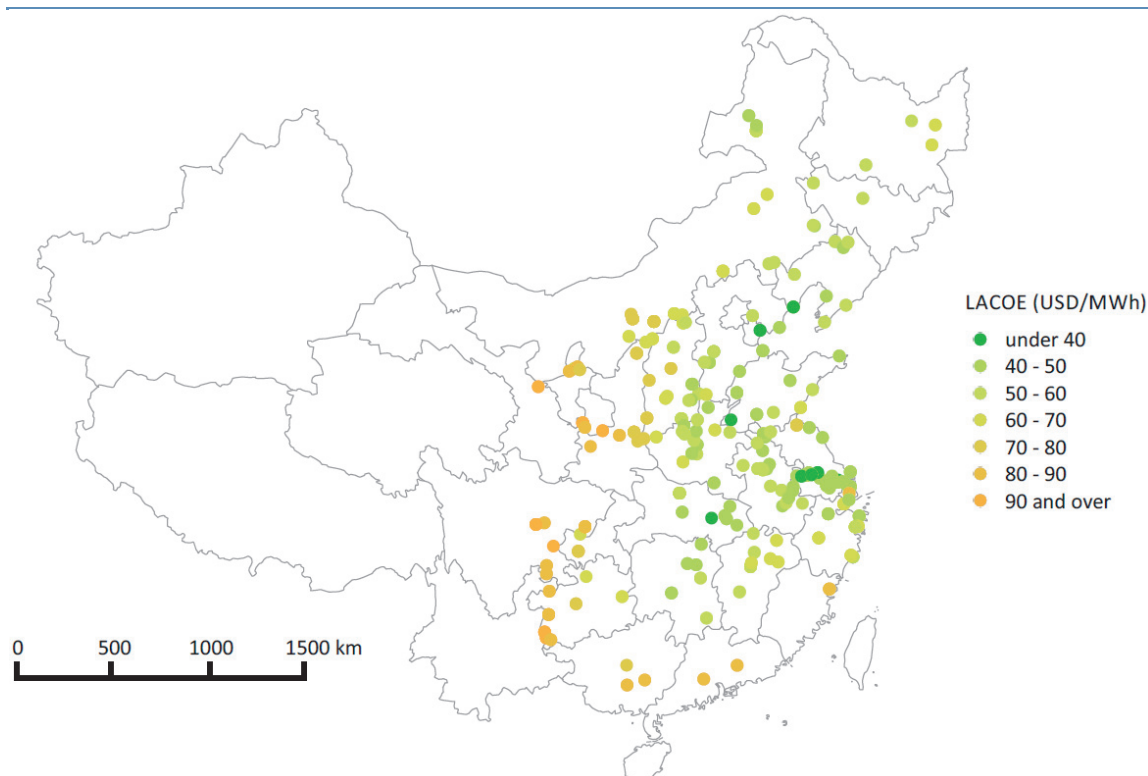
<sup>19</sup> In the calculations presented here, the value of underlying power plant asset and its payback period are considered to remain unchanged after retrofit. In reality, it is likely that rebuilding the unit at the same time as the retrofit will be slightly more attractive than suggested by our calculations as the payback period for the remaining asset value will be extended.

As noted earlier, the LACOE analysis presented here has considered only saline aquifer CO<sub>2</sub> storage. Many of the CCS projects under development in China are linked to potential EOR operations (GCCSI, 2015) and revenues from oil sales would provide income that could, in part, offset the LACOE that would otherwise raise the overall cost of electricity production. As has been seen in North America, the combination of EOR and CCS can significantly reduce the level of additional public funding or policy support required per tonne of CO<sub>2</sub> emissions avoided – though the volume of avoided emissions may ultimately be lower (IEA, 2015b).

### *The lowest cost retrofit options are distributed across eastern provinces*

The spatial distribution of LACOE values for CEC units shows a general trend towards lower costs in eastern provinces (Figure 20). As was shown in Figure 19, CO<sub>2</sub> transport and storage costs are a determining factor for higher LACOE values for many units. The map therefore indicates that access to CO<sub>2</sub> storage is better in eastern provinces (approximately within a 1 000 km radius of Hefei) and that this can explain why units outside these regions tend to have higher LACOE. Among the lower cost units, individual differences in age, size and other characteristics are likely to determine relative attractiveness, but it is interesting to note that the units with the very lowest costs are not all clustered together. This shows that there are a range of regions in eastern China where retrofits may become cost-effective first.

**Figure 20 • Geographic distribution of LACOE for CEC plants identified as suitable for retrofit**



Note: This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Source: IEA analysis.

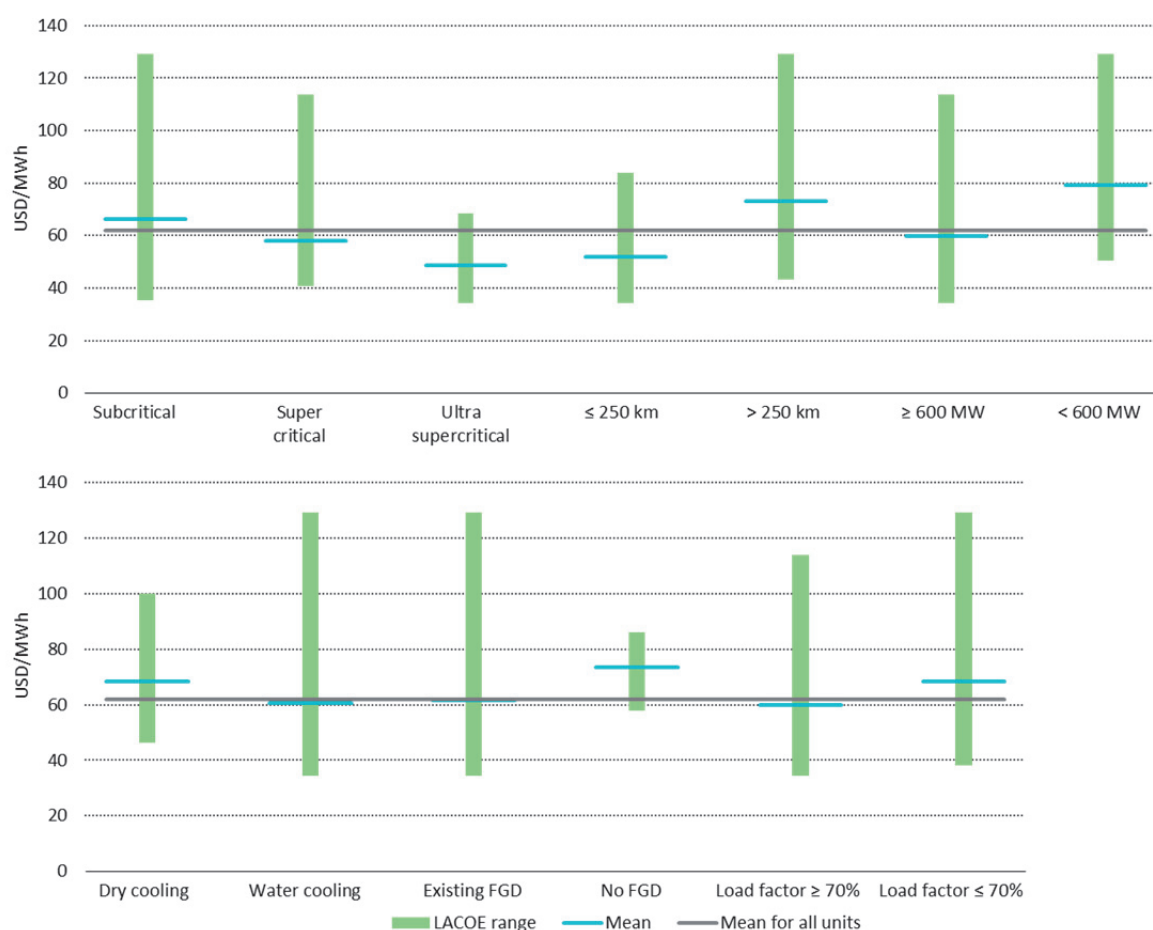
### *The impact of key cost factors*

The sensitivity of the LACOE to factors such as unit size, steam conditions and CO<sub>2</sub> transport distance provides some insight into the most important cost components. This can be used as a guide to the power plants in a portfolio that might make more interesting retrofit candidates.



Some subsets of CEC units that have a shared characteristic are lower than other subsets that do not share this attribute (Figure 21). From this approximate comparison it can be seen that higher costs on average are most closely associated with plants that are smaller, without FGD and further from their favoured CO<sub>2</sub> storage site. Ultra-supercritical steam conditions and proximity to suitable CO<sub>2</sub> storage are both indicators of lower average costs, while load factors and cooling types have less impact.

**Figure 21 • Ranges of LACOE for sub-categories of CEC units**



Notes: Categorisation of subcritical, supercritical and ultra-supercritical steam conditions of units as assigned by CEC. Distances refer to distance to the lowest-cost CO<sub>2</sub> transport and storage option for each unit. Load factors refer to average load factor in 2012/13 as adopted for the LACOE calculation. 250 km was selected as a threshold distance based on the work of Dahowski et al., (2013).

Source: IEA analysis.

The units with the lowest costs are recently constructed. Considering only the 10% of suitable units that have the lowest LACOE values (50 units with LACOE under USD 45/MWh), 42 were commissioned after 2005. However, the plants vary widely in terms of other factors, illustrating some of the cost trade-offs. For example, just 16 of these units find their lowest-cost transport and storage option within 150 km, and just 33 within 250 km. Thus, longer transport distances can be attractive when CO<sub>2</sub> capture and CO<sub>2</sub> storage costs are low.

In terms of steam conditions, while almost all the 50 units are 600 MW or over, not all are categorised as ultra-supercritical. Our analysis suggests that it can be just as cost-effective to retrofit large, subcritical plants with efficiencies of 39% or over and good access to CO<sub>2</sub> storage. Of the 29 units in this subset classified by CEC as subcritical, most would require rebuild of the steam cycle to realise these low costs over the lifetime of the retrofitted unit. Six of the 50 units –

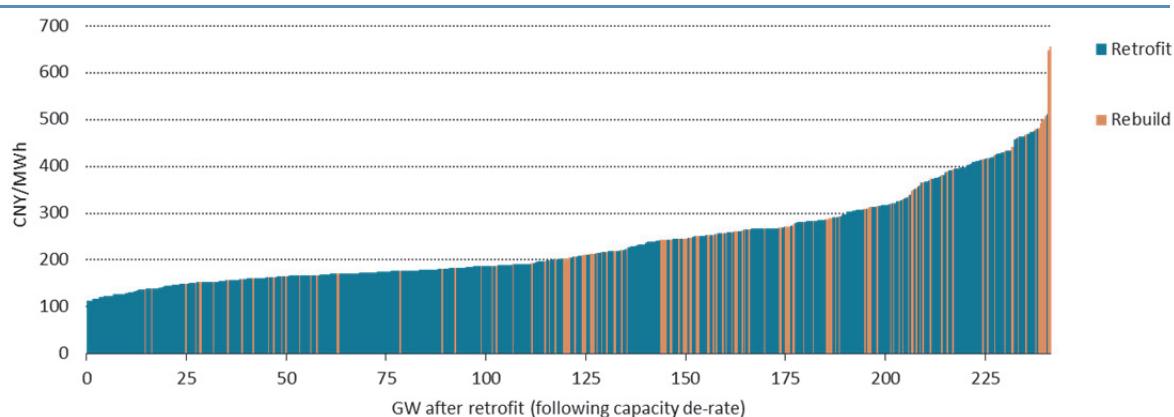
all at different plants in Hebei, Shanxi and Inner Mongolia – have relatively low LACOE despite using dry cooling. These units are all young, large and have high load factors. One of them has the shortest CO<sub>2</sub> transport distance in the subset: 25 km.

The implication of this analysis is that it is unwise to set rigid thresholds for retrofit criteria. The most cost-effective units to be retrofitted may seem far from storage, may be subcritical or may be in regions of low water availability. The trade-offs between cost factors mean that it is necessary to include as many relevant factors as possible when guiding the search for retrofit candidates or when setting policy to stimulate investments in CCS retrofits.

### *An estimate of representative costs for China*

Compared to the United States, CCS retrofit costs are likely to be lower in China as equipment, materials and, especially, labour are generally less costly. While the precise cost multiplier for these cost elements is difficult to estimate, a conversion has been undertaken to give an idea of representative retrofit costs in China (Figure 22). This shows that the 100 GW of existing coal-fired units with the lowest retrofit costs have a maximum LACOE of CNY 168/MWh.

**Figure 22 • LACOE curve adjusted to representative Chinese cost levels**



Source: IEA analysis.

In 2015, China's wholesale rates for thermal power generation are in the range of CNY 35/MWh to CNY 45/MWh (Haugwitz, 2015). The feed-in-tariff for utility scale solar electricity is in the range of CNY 90/MWh to CNY 100/MWh, which is similar to the LACOE of CCS retrofits at the lower end of the estimated range. The low carbon electricity from a CCS retrofit potentially has a higher value to the electricity system as it has high availability all year and is responsive to changes in supply and demand. Both solar and CCS costs are expected to fall by 2025, and the effective support to CCS may be further reduced for projects that are combined with EOR. In the same period, power sector reforms are anticipated in China. Nevertheless, this analysis suggests that CCS retrofits at the lower end of the LACOE range are within acceptable levels of support for low-carbon and innovative technologies in China.

## Sanity check: is the CO<sub>2</sub> storage resource in China sufficient?

The analysis of access to CO<sub>2</sub> storage presented in earlier sections only considers the retrofit of each unit in isolation, but in reality there might be competition<sup>20</sup> for the best storage sites when multiple units are retrofitted. This might mean that the first CCS projects in a region would construct pipelines to the lowest-cost CO<sub>2</sub> transport and storage options and subsequent projects would need to exclude the same pore space from their CO<sub>2</sub> storage options. This could push up the costs of CO<sub>2</sub> transport and storage for the later projects in a region and change the order of units in terms of retrofit costs. Importantly, it is conceivable that some units could find themselves without a CO<sub>2</sub> storage site within an accessible distance as a result of competition effects. To explore the extent to which competition for the lowest cost CO<sub>2</sub> storage sites might increase overall costs, a simulation was performed (Box 5).

The results of this simulation show that even if multiple power plants were retrofitted, competition between them for storage sites would not have a large impact on CO<sub>2</sub> transport and storage costs. An average increase of USD 1.4/tCO<sub>2</sub> might be expected. The results show that competition effects can reduce the total retrofit potential if a constraint of 250 km is placed on transport distances, rather than 800 km. Longer transport distances relieve competition without significantly raising average transport and storage costs.

In total, 20 years of storage from the 310 GW of capacity that meets the suitability criteria would deplete China's total estimated onshore saline aquifer storage resource by 1.1%.

### Box 5 • How competition for storage sites might affect feasibility and cost

The simulation of competition for storage sites minimised total CO<sub>2</sub> transport and storage costs for a scenario in which all retrofit candidate units were retrofitted. In the model, priority units were allocated their preferred storage options for 20 years of captured emissions. These storage sites were then unavailable to the next units to be considered. Only units meeting all suitability criteria were included in the simulation as they might be considered to be the maximum number of units that might compete. As CO<sub>2</sub> capture costs were not included in this competition analysis, it is not possible to apply the results to the cost curve presented for the phase 2 results. Such an approach would be recommended for future analyses. Further information on the methodology can be found in Annex 5.

The key metrics that can be assessed in this analysis are:

- Decreases in the number of units that meet the suitability criteria
- Increases in distances to storage sites as a result of competition effects
- Increases in transport and storage costs as a result of competition effects

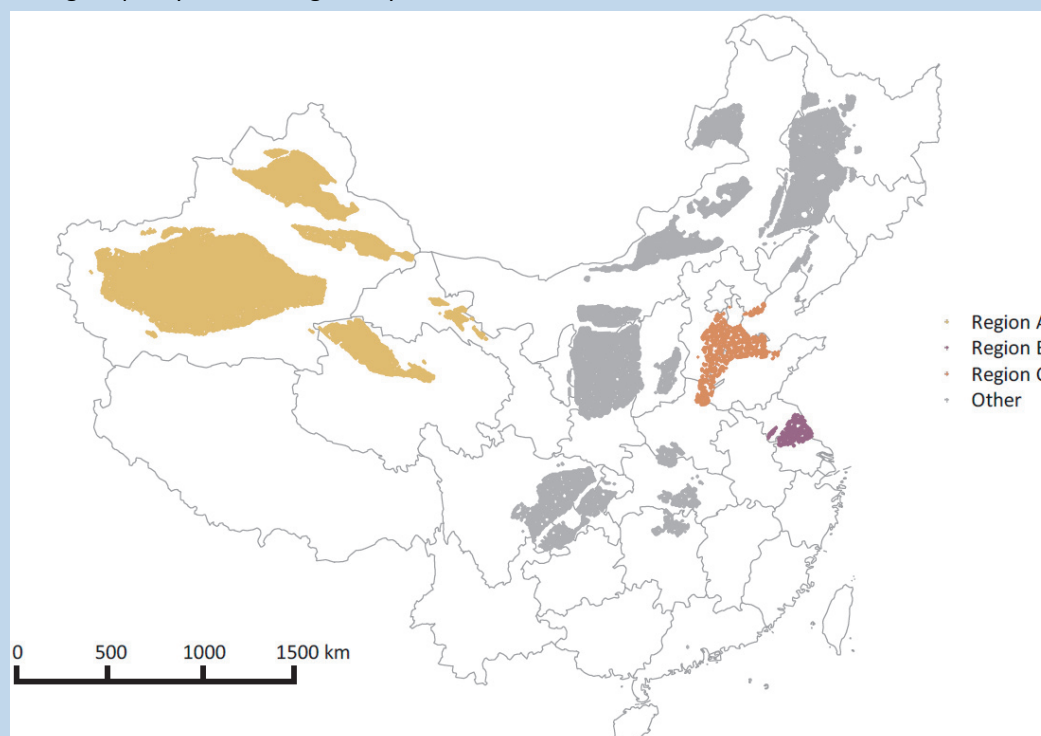
The results can be considered to be the higher end of the level of impacts because the analysis assumes that all suitable units are retrofitted. Furthermore, the analysis assumes that the costs of transport between a given power plant unit and a storage site are the costs of a pipeline sized for the flow of CO<sub>2</sub> from that unit. This neglects the potential for lower CO<sub>2</sub> transport and storage costs that arises when multiple units are retrofitted. Costs will be lower when transport infrastructure is shared between power plant units that are close to one another and CO<sub>2</sub> storage sites that are close to one another. In addition, while this analysis only considers existing coal-fired power plants, infrastructure could be shared with CO<sub>2</sub> captured from power plants built after 2013, coal-to-chemicals facilities, steel mills, refineries or gas-fired power plants. If this raised the overall level of CCS activity in China it would, of course, also increase competition effects, creating a trade-off in terms of costs.

<sup>20</sup> Competition as used here refers to both direct competition between two units for a shared preferred CO<sub>2</sub> storage location and the temporal impacts of the first CCS projects accessing the best CO<sub>2</sub> storage resources and making these unavailable to later projects.

Only six units no longer have access to a suitable CO<sub>2</sub> storage site within 800 km due to competition, representing just 4 GW. For the remaining 306 GW, 259 GW are paired with a different storage site due to competition effects, but this is generally not accompanied by a large increase in distance. For the 306 GW, the average distance to CO<sub>2</sub> storage is increased by 39 km and the average cost of CO<sub>2</sub> transport and storage rises by USD 5.5/tCO<sub>2</sub> (20%). Looking only at the 100 GW of units found to have the lowest costs in phase 2 of the analysis, the proportional increase in CO<sub>2</sub> transport and storage costs due to competition is similar, but in absolute terms it is only USD 1.4/tCO<sub>2</sub> on average. This lower figure may be more representative of the additional costs due to competition if multiple units were retrofitted.

The results are more pronounced if the maximum CO<sub>2</sub> transport distance is limited to 250 km, as has been suggested by Dahowski et al., (2013). Of the 310 GW that meet the suitability criteria, 234 GW have access to suitable storage within 250 km, and 137 GW still have access to suitable storage within 250 km as a result of competition effects. For this 137 GW, the average distance to a storage site increases by only 1 km (from 169 km to 170 km) due to competition effects and the average cost of transport and storage increases by only USD 3/tCO<sub>2</sub>.

The results for the analysis whereby CO<sub>2</sub> transport distances were limited to 250 km indicates the potential geographical impacts of competition effects. Firstly, competition in the North-Western region of China (Region A in the below figure) is not a concern for CCS retrofits of existing plants as just two of the units meeting the suitability criteria find their lowest-cost storage option in this region and competition effects increase this to eight (8) units. Across China, there is a “displacement” from a unit’s preferred storage region (if there were no other retrofits undertaken) to a storage site in a different geological area for 32 units. The most common displacements between regions are those from Jiangsu (Region B) and Hebei and Shandong (Region C) to other regions. However, this was not because Regions B and C have insufficient capacity for the potential retrofits in Eastern China. Instead, it is because storage costs vary between storage sites within a region and the combined CO<sub>2</sub> transport and storage costs could be marginally improved by moving to sites in a different region instead of a more costly site in the same region. In the simulation, 20 years of CO<sub>2</sub> storage from all units whose lowest cost CO<sub>2</sub> transport and storage option is in Regions B or C would reduce the total storage capacity of these regions by 10%.



Note: This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area. Source: CAS.

## Implications for strategy and policy

### Key points

*Detailed exploration of the storage resource in key areas of China is required. Today, there is generally good knowledge of subsurface geology in China, but the detailed geology of potential storage sites is less well developed.*

*There is a clear need to continue **support for post-combustion capture projects** in China, promoting technologies to increasingly larger scales as experience and viability expands, in order to support cost reduction across the value chain of a CCS retrofit*

*A third key component of a Chinese strategy to be prepared for retrofitting CCS should be to **ensure that newly built coal-fired power plants are highly suitable for retrofitting.***

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There are various important steps that can be taken by government and industry in China to ensure that retrofit of CCS is an available and attractive option in the coming decades. Three particular areas are highlighted:

- Boosting CO<sub>2</sub> storage development.
- Continuing technology innovation and cost reduction.
- Ensuring CCS-readiness.

## CO<sub>2</sub> storage exploration and development

This paper makes clear that the suitability of a coal-fired unit for retrofitting with CCS is not just about whether and how to fit CO<sub>2</sub> capture equipment. Factors such as the proximity to suitable CO<sub>2</sub> storage can have a major impact on costs and in some cases will represent the largest component of additional electricity generation costs. The development of suitable saline aquifer sites that can store the CO<sub>2</sub> from CCS retrofits can have timescales of a decade. This poses a challenging coordination problem: in order to take a retrofit decision for a plant, the operator must have a high degree of confidence that transport and storage is available. Moreover, the risks associated with developing storage are inherently different from those associated with installing CO<sub>2</sub> capture, the former being an earth system rather than an engineered system.

Today, there is generally good knowledge of subsurface geology in China, but the detailed geology of potential storage sites is less well developed. Before CCS is expected to be widely deployed, it will be vitally important to undertake detailed exploration of the storage resource in the most promising areas. The most promising areas are not only those where the estimated injectivity and capacity are most favourable, but also those in good proximity to plants that might be retrofitted with CO<sub>2</sub> capture or built with CCS from the outset. The challenge of balancing the risk and reward of exploring natural resources is commonplace in the oil and gas industry, which is likely to be a major player in the CO<sub>2</sub> storage business. China is not alone in facing this challenge, which is a key concern for CCS globally (IEA, 2015d).

Consequently, there is an imperative to continue this work for onshore saline aquifer sites – particularly in Eastern regions of China where populations and industries are most concentrated. The case for furthering the current work on offshore CO<sub>2</sub> storage also remains very strong. Offshore storage offers the possibility to avoid pipelines through difficult or populated terrain

and to reuse existing oil and gas infrastructure, but much more information about costs and capacities is needed before it could be a basis for a retrofit decision on a large power plant unit.

## Innovation and the development of Chinese capacity

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The costs of CCS can be reduced significantly from where they are today. There are opportunities for cost reduction in all parts of the value chain of a CCS retrofit, especially in the capital and operational costs of post-combustion CO<sub>2</sub> capture (IEA, 2015d). Much of this cost reduction can come from the experience that firms will gain from building and operating large-scale projects using CCS technologies. Thus, as China expands its use of CCS alongside other countries around the world, costs will fall due to learning-by-doing and economies of scale. Without a doubt, innovations will emerge during the design and operation of CO<sub>2</sub> capture plants that will help subsequent plants to be cheaper and more efficient.

Compared to many other countries and regions, China possesses a tremendous opportunity to drive down the costs of CCS and generate a world-leading CCS industry. Because China's use of coal in power generation is so extensive and its market so large, it has the potential for unparalleled economies of scale. The recent construction of so many of China's coal-fired power units, their large unit size and their existing pollution controls make retrofitting CCS in the 2025 to 2035 timeframe a potentially very attractive solution for China's ambitious climate targets. Furthermore, the location and extent of geological CO<sub>2</sub> storage does not appear to be a significant constraint. In order to bring costs down rapidly, China has the opportunity to undertake a stepwise programme of CCS deployment on existing and new plants that takes full advantage of economies of scale and the benefits of standardisation, just as was achieved for Chinese coal-fired plants between 2005 and 2015.

Innovation in CO<sub>2</sub> capture will not happen without concerted effort, however. In the absence of a large commercial market for CO<sub>2</sub>, CCS technologies will remain largely reliant on policy and government support in the next decade.<sup>21</sup> To improve CO<sub>2</sub> capture so that it can be available for power plant retrofits in the 2025 to 2035 timeframe requires four kinds of action from government and industrial partners:

- Support **post-combustion capture projects** at power plants of increasingly larger scale and reinvest the knowledge arising from each one into the subsequent projects. For cost reduction, this is the most important action in this list because it will bring together engineers and managers who can identify savings and develop standardised value chains for future projects. The next steps for China could be projects of 1 MtCO<sub>2</sub>/yr and over<sup>22</sup>, which will be most impactful if they operate under realistic commercial conditions for as many years as possible.
- Invest in **R&D for technologies that can reduce the capital and efficiency-related costs** of CCS retrofits, including better solvents, better materials and designs that are appropriate for

<sup>21</sup> In China, an exception to this is the use of CO<sub>2</sub> for the production of methanol from coal, via the water-gas shift reaction that converts the CO<sub>2</sub> in synthesis gas to CO feedstock for methanol. Methanol synthesis is not a realistic market for CO<sub>2</sub> from power plant retrofits, however. This is because the CO<sub>2</sub> from post-combustion CO<sub>2</sub> capture is a significantly more expensive feedstock than that captured from coal-to-chemicals plants and power plants do not provide a source of hydrogen, which is needed for the water-gas shift reaction. While CO<sub>2</sub> sales to methanol or other chemical producers could in theory provide a demand for CO<sub>2</sub> that would incentivise lower CO<sub>2</sub> capture costs from power plant retrofits, this use of the CO<sub>2</sub> would not have the emissions reduction impact of geological CO<sub>2</sub> storage and would at least double the number of retrofitted plants that would be needed for the same level of emissions reduction.

<sup>22</sup> From 2016, the largest post-combustion capture plant in the world will be the Petra Nova Carbon Capture project in Texas, United States, at 1.4 MtCO<sub>2</sub>/yr. Two post-combustion projects of a similar size are under development in China at coal-fired power plants, both targeting operation by 2019 (GCCSI, 2015). These are in Shandong and Guangdong.



Chinese power plants. Studying and piloting the retrofitting of oxy-fuel technology should also be actively considered and implemented. This may include international collaboration on projects and technologies.

- **Provide power plant owners and operators with policy guidance** about their options for retrofitting CCS and how their retrofitted plants will continue to be profitable under Chinese climate policy. This includes the development of appropriate standards and procedures for undertaking all parts of the CCS value chain under Chinese law.
- **Help businesses that can provide CO<sub>2</sub> capture and storage solutions** in China to develop supply chains in a coordinated manner. These two activities may evolve as separate businesses or they may be supplied as a package. While the differences in the nature of the activities means that the former may be more appropriate, the most important outcome is that a commercial market for these services is available in China after 2025.

In China, several projects are already underway to explore the retrofit of CO<sub>2</sub> capture to existing coal-fired units. These projects are generating valuable information about the costs, operation and market conditions for CCS retrofits in China. These projects include the Yuhuan power plant pilot project, which is at a site that meets many of the suitability criteria for retrofitting CCS (Box 6). In addition, some plants, such as the Shidongkou power plant in Shanghai, have already retrofitted CO<sub>2</sub> capture at a smaller scale. At Shidongkou, 1 ktCO<sub>2</sub>/yr has been captured since 2009 and sold as food-grade CO<sub>2</sub>.

#### Box 6 • Yuhuan CCS retrofit project

Huaneng Group, a member of CEC, has undertaken a pre-feasibility study of a CCS retrofit at its Yuhuan coal-fired power plant. It is the first full-chain CCS retrofit project in South China and the first in China to look at offshore CO<sub>2</sub> storage. The Yuhuan power plant has the following features:

- Size: Four 1000 MW units
- Age: Production at all units began between November 2006 and November 2007
- Load factor: 76-81% in 2012/13
- Location: Zhejiang Province
- Design efficiency: 44%
- Pollution control efficiency: 99.7% dust removal, 95% SO<sub>2</sub> removal, 80% NO<sub>x</sub> removal
- Cooling: open cooling
- Distance to preferred CO<sub>2</sub> storage site: 150 km offshore, 617 km onshore

The project envisages the capture of 8% of the CO<sub>2</sub> (500 ktCO<sub>2</sub>/yr) from one of two new 1000 MW units that are to be built in coming years. Post-combustion CO<sub>2</sub> capture has been selected for its maturity and minimal impact on the power plant. The technology, which combines the flue gas pre-treatment and capture stages using inter-cooling and flashing methods, has been developed by Huaneng and trialled at the Shidongkou power plant. The solvent, also developed internally, has been trialled at a facility in Beijing and is expected to operate with a 94% capture rate. The capture facility as designed would occupy 9 000 m<sup>2</sup>.

The pre-feasibility study estimated that the levelised cost of CO<sub>2</sub> capture and compression could be around CNY 300/tCO<sub>2</sub> (USD 48/tCO<sub>2</sub>). Based on calculations so far, the project could have a positive net present value (NPV) if there were a carbon price of CNY 50/tCO<sub>2</sub> and if clean electricity delivered to the grid were given a subsidy of CNY 100/MWh. Due to relatively low volumes of CO<sub>2</sub> to be transported, the most attractive option is thought to be to transport the CO<sub>2</sub> to the offshore storage site by ship, which would be more economically viable if the ship were rented rather than owned (Wang, 2015).

## Socio-economic components

In addition to technology development, there is need to study wider socio-economic impacts of CCS retrofitting as one element of energy transformation. These include the impact on electricity tariffs, the employment impact of CCS retrofit construction and operation, the impact on future use of coal and other trade-offs and benefits associated with CCS retrofitting and other different low-carbon options.

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## CCS readiness considerations

The third key component of a Chinese strategy to be prepared for retrofitting CCS is to ensure that as many newly built coal-fired power plants are highly suitable for retrofitting. Even if all plants built from today in China are ultra-supercritical plants, their emissions would likely pose a challenge in 2040 if they were not retrofitted with CCS before the end of their design lifetimes.

The 705 MtCO<sub>2</sub>/yr emitted in 2040 from all Chinese electricity generation in the IEA WEO 450 scenario are equivalent to 900 TWh from ultra-supercritical plants burning high grade coal at 800 gCO<sub>2</sub>/kWh.<sup>23</sup> At 75% load factors, this amount of electricity would be generated by 150 GW of ultra-supercritical coal plants. Since 2005, 130 GW of ultra-supercritical plants have been built in China and would be expected to still be in operation after 2040. Thus, if the WEO 450 emissions trajectory were followed, there would be only 20 GW of headroom for new coal-fired power plants in China and no space for any gas-fired plants unless CCS were retrofitted to a portion of the thermal plants or load factors settled at much lower levels. Even if a less stringent emissions trajectory were followed, it would be unlikely to provide comfortable headroom for the 68 GW of coal-fired capacity under construction in China in 2015, and the 406 GW in planning, to operate at high load factors without any retrofitting of CCS.

While 55% of installed CEC capacity appears suitable for retrofitting CCS, there is no reason why it is not possible to push this number closer to 100% for plants built after 2015 and to place newer plants at the low end of the cost curve. To realise this ambition, the factors discussed in the analysis for this report provide a strong foundation for a CCS readiness strategy.

A new coal-fired unit that is designed to be CCS ready must demonstrate much more than a technical suitability for the addition of post-combustion CO<sub>2</sub> capture (IEA/CSLF, 2010). As mentioned above, it is technically feasible to retrofit almost any unit with CO<sub>2</sub> capture as long as space on site is available. CCS readiness therefore relates just as much to the commercial opportunity and the access to CO<sub>2</sub> storage as it does to the power plant design. This is plainly described in regulations implemented by the government of Canada and by the European Union (Box 7).

In the case of Canada, new units that are designed to permit integration with a carbon capture and storage system are temporarily exempted from the national emission performance standard (420 g/kWh) until 2025 or until the conditions for retrofitting the unit with CCS become attractive (Canada, 2012). As a result, CCS ready or CCS-equipped plants are the only new coal-fired plants that can be permitted in Canada. As with the European Union definition, Canada also requires submission of an economic assessment of CCS retrofit, accompanied by an implementation plan.

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<sup>23</sup> Approximately 800 g/kWh (net) is the best performance of an ultra-supercritical plant using known materials today (EPRI, 2015).

**Box 7 • European Union definition of CCS readiness**

In 2012, the European Commission communicated guidelines on the use of revenues arising from the European Emissions Trading System for investment aid to new highly efficient power plants (EC, 2012). The highest levels of allowable aid (10% to 15% of eligible costs) are reserved for power plants that are constructed CCS ready. CCS readiness has been defined by the European Union as follows:

*'CCS-ready' means that an installation has demonstrated that suitable storage sites are available, that transport facilities are technically and economically feasible and that it is technically and economically feasible to retrofit for CO<sub>2</sub> capture, as soon as sufficient market incentives in the form of a CO<sub>2</sub> price threshold are reached. In particular, CCS-ready requires:*

- *demonstration of the technical feasibility of retrofitting for CO<sub>2</sub> capture. A site-specific technical study should be produced showing in sufficient engineering detail that the facility is technically capable of being fully retrofitted for CO<sub>2</sub> capture at a capture rate of 85% or higher, using one or more types of technology which are proven at pre-commercial scale or whose performance can be reliably estimated as being suitable*
- *control of sufficient additional space on the site on which capture equipment is to be installed*
- *identification of one or more technically and economically feasible pipeline or other transport route(s) to the safe geological storage of CO<sub>2</sub>*
- *identification of one or more potential storage sites which have been assessed as suitable for the safe geological storage of projected full lifetime volumes and rates of captured CO<sub>2</sub>*
- *demonstration of the economic feasibility of retrofitting an integrated CCS system to the full/partial capacity of the facility, based on an economic assessment. The assessment should provide evidence of reasonable scenarios, taking into account CO<sub>2</sub> prices forecasts, the costs of the technologies and storage options identified in the technical studies, their margins of error and the projected operating revenues. The assessment will indicate the circumstances under which CCS would be economically feasible during the lifetime of the proposed installation. It should also include a potential CCS implementation plan, including a potential timetable to entry into operation*
- *demonstration that all relevant permits to implement CCS can be obtained and identification of procedures and timelines for this process.*

The Canadian regulation also recognises an important factor of CCS readiness: it needs to be maintained over time. Operators of CCS ready units in Canada must submit an implementation report each year that describes the steps towards retrofitting that have been taken that year and any changes to plans or economic outlook. CCS ready status is not maintained if the allocated space onsite is not continuously reserved and if the storage sites and transport routes are not monitored for any evolutions that could affect the implementation plan.

In China, the following factors would need to be taken into account in any assessment of CCS readiness:

- The likely longevity of the proposed coal-fired plant under anticipated Chinese policies relating to local pollution, climate change and natural resources.
- Design of the power plant unit to ensure that heat can be provided with minimal impact on power generation efficiency, either from the steam turbine or an external heat source.
- Impact of the retrofit on local water availability.

- Distance to a good quality CO<sub>2</sub> storage site with adequate capacity for the expected lifetime of the retrofitted plant, and without likely competition from other CO<sub>2</sub> capture plants in the “carbonshed”<sup>24</sup> that might prevent the future retrofit.
- Reservation of sufficient available space on site for the CO<sub>2</sub> capture equipment.
- The possible pipeline routes if the plant is to use onshore CO<sub>2</sub> storage, and whether they are likely to pose any significant geographic, political or social challenges, either now or in the future.
- The total expected economic costs and benefits of the future retrofit in comparison with other possible new build plant locations and designs, taking into account such factors as the respective future values of imported and domestically produced coal, the needs of the local and national power grids and the policy options for rewarding low carbon electricity generation.
- How the conditions for supporting the future retrofit will be maintained and developed during the operation of the unit before the time of retrofit.

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<sup>24</sup> “Carbonsheds” are regions analogous to watersheds in which the estimated cost of transporting CO<sub>2</sub> from any location in the region to the storage site it encompasses is cheaper than piping the CO<sub>2</sub> to a storage site outside the region (Eccles, 2014). Building on the discussion in this study, this definition can be extended to include the combined costs of CO<sub>2</sub> transport and storage, and not the transport costs alone.

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## Annex 1 The policy context for Chinese coal

### Local pollution

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China's air pollution levels are far in excess of the safety levels established by the World Health Organisation. Persistently high levels of smog are predominantly caused by emissions of particulate matter with diameter less than 2.5 and less than 10 micrometres (PM 2.5 and PM 10). The main sources of PM 2.5 in highly populated areas are coal combustion, including in small boilers such as residential uses, and diesel vehicles.

Campaigns to improve air quality in major urban areas were implemented in the run-up to the 2008 Beijing Olympics and the Shanghai World Expo in 2010. For the former, numerous heavy industrial and coal-fired power plants within the Beijing municipality were relocated or closed. Additionally, urban areas have instituted stricter vehicle ownership and driving restrictions to limit vehicle emissions during periods of serious air quality hazards. Public transport infrastructure has also been expanded, including the world's longest high-speed rail network.

In 2011, new standards for pollutant emissions from power plants were adopted for mercury (0.03 mg/m<sup>3</sup>), sulphur dioxide (200 mg/m<sup>3</sup>), nitrogen oxides (100 µg/m<sup>3</sup>) and particulate matter (30 mg/m<sup>3</sup>) (WRI, 2012).<sup>25</sup> These levels are comparable to those currently in force in the European Union and the United States, both of which are, however, likely to adopt stricter limits in coming years.

In 2013, China's State Council issued an Action Plan for Air Pollution Prevention and Control. The objective was to improve air quality and reduce air pollution, especially in three key regions. Stated objectives for 2017 are:

- Annual average concentration of PM 2.5 reduced by 25% in Beijing-Tianjin-Hebei, 20% in the Yangtze River Delta and 15% in the Pearl River Delta.
- Annual average concentration of PM 10 in all second- and third-tier cities reduced by at least 10% from the 2012 level, accompanied by an increase in the number of days with clean air.
- Annual average concentration of PM 2.5 in Beijing controlled at 60 microgrammes per cubic metre.

From January 2015, new, more stringent standards for commercial coal came into force that limit sale or import of coal with greater than 3% sulphur content (1.5% for lignite) and 40% ash content (30% for lignite), and impose stricter limits on trace elements (NDRC, 2014a). For coal transported over distances of more than 600 km, tighter standards apply: calorific values of 18 GJ/tce (16.5 GJ/tce for lignite); sulphur content of 2% (1% for lignite); and ash content of 30% (20% for lignite). For households and smaller users in the Beijing-Tianjin-Tangshan metropolitan and neighbouring areas, the Yangtze River Delta and the Pearl River Delta area, the standards are stricter: 1% sulphur content and 16% ash content.

In terms of enforcement, new provisions under the Environmental Protection Law have, since January 2015, allowed non-profit organisations to use the courts as interested parties to sue for environmental damages, including in cases where the environmental or ecological damage has not yet occurred, but where significant risk of public harm can be shown. The first case by a non-profit against an industrial polluter has already been accepted by a court in Shandong province in an indication that enforcement may be more effective in future years (Qin, 2015).

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<sup>25</sup> Limits are higher for plants in four provinces with high sulphur coal and for plants built before 2004.

## Greenhouse gases

Chinese per capita CO<sub>2</sub> emissions increased threefold between 1990 and 2012 to 6.1 tonnes of CO<sub>2</sub> per capita per year. This remains lower than the average of IEA member countries (10.4 tCO<sub>2</sub> per capita) but is nearing the EU average (6.9 tCO<sub>2</sub> per capita). In absolute terms, China was the largest country emitter of CO<sub>2</sub> in 2012, at 8 251 million tonnes of CO<sub>2</sub> (MtCO<sub>2</sub>), compared to the United States at 5 074 MtCO<sub>2</sub>.

The 2014-20 National Plan on Climate Change aims for a 40-45% cut in CO<sub>2</sub> emissions per unit of GDP by 2020, from 2005 levels. Since the 11th FYP, China has broadly been on course to meet this target. In the energy sector, effort has been directed at improving energy conservation and energy efficiency, with China generally on track to reduce CO<sub>2</sub> per unit of GDP by 17% between 2010 and 2015, and energy intensity by 16%. CO<sub>2</sub> emissions per unit of GDP in 2013 were 4.3% lower than in 2012, and 29% lower than in 2005, equivalent to a cumulative reduction of 2 500 MtCO<sub>2</sub> (NDRG, 2014b). China's recent Work Plan for Controlling Greenhouse Gas Emissions during the 12th FYP is an important guidance document assigning carbon intensity reduction targets to all provinces, autonomous regions and municipalities.

49% of China's CO<sub>2</sub> emissions are from electricity generation, of which 98% are from coal combustion. The average carbon intensity of China's electricity generation has been significantly lowered from 1002 grams of CO<sub>2</sub> per kilowatt hour (gCO<sub>2</sub>/kWh) in 1990 to 819 gCO<sub>2</sub>/kWh in 2012.

The twelfth Five-Year Plan (FYP) (2011-2015) described goals to "gradually develop a carbon trading market". In preparation, five cities and two provinces in China were directed to develop and implement pilot emission trading schemes (IEA, 2014a). By 2014, all seven pilots were operational. It is expected that these pilots will provide a foundation for a nationwide emissions trading system for greenhouse gases that could be implemented at the beginning of the 13th FYP period.

## Energy mix

In response to air quality, energy security and climate concerns, China has established a number of policies for raising the proportion of energy from non-fossil sources to 15% by 2020 and 20% by 2030, from 12% in 2012. The Energy Development Strategy Action Plan (2014-2020) targeted a fall in the share of coal in Chinese primary energy supply from 66% to 62% by 2020 and a cap on total primary energy of 4.8 billion tce (State Council, 2014). This would allow coal consumption to increase to 3.0 billion tce by 2020, a growth rate of just 0.4% from 2013 to 2020, compared to average growth 8.6% per year over the previous decade. The Plan also foresees an increase of the share of natural gas in Chinese primary energy supply to 10% by 2020, from 4% in 2012, resulting in large part from substitution of natural gas for coal in residential applications. This gas objective is to be supported by increased conventional and unconventional resource exploration and a target for pipeline infrastructure to total 120 000 km by 2020. While these targets indicate the government's near-term ambition, it is understood that the values themselves in question due to upward revisions in coal consumption data in late 2015.

The National Energy Administration's 2020 targets for non-fossil electricity include the following (IEA, 2015):

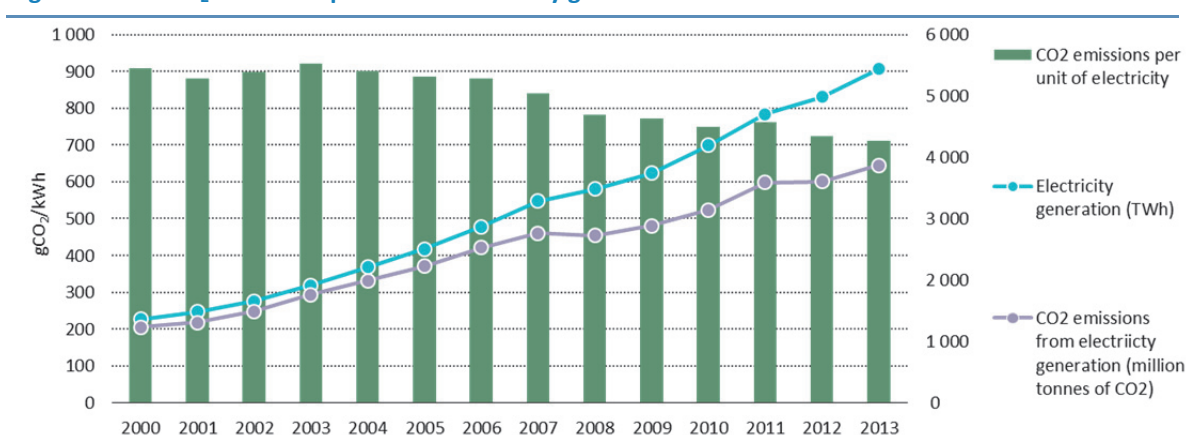
- 420 GW hydropower capacity
- 170 GW onshore wind power
- 55 GW nuclear power

- 47 GW solar photovoltaic (PV) power
- 30 GW offshore wind
- 30 GW biomass
- 3 GW concentrating solar power (CSP)

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These levels would represent a doubling of China's installed non-fossil capacity in 2013 and 38% of the expected global growth in renewable power capacity between 2013 and 2020.<sup>26</sup> The result would be a continuation of the decline in emissions per unit of electricity generation in China, which declined between 2003 and 2012 at an average rate of 18 gCO<sub>2</sub>/kWh per year (2.2%) (Figure A.1.1).

Figure A.1.1. • CO<sub>2</sub> emissions per unit of electricity generation in China



Source: IEA statistics.

At a regional level, it was announced in September 2013 that new build coal-fired power plants will no longer be approved in the major centres of population including “clean air, less coal” areas that include Beijing, Tianjin, the Yangtze River delta and Pearl River Delta. In these areas, construction of CHP facilities using coal will be permitted and, by 2020, it is stated that 28% of coal-fired electricity generation should be CHP (NDRC, 2014c). In Beijing city it has been decided that existing coal-fired power will be phased out and replaced by natural gas-fired generation by 2017, and a 65% maximum target for the share of coal in primary energy in 2015 has been set. Targets for limiting coal consumption have been set in almost half of China's provinces and regions (Table A.1.1).

<sup>26</sup> 2014 Renewable Medium term Market Report



**Table A.1.1. • Coal consumption targets for Chinese provinces with announced goals for 2012 to 2017**

Province/region	Consumption in 2012 (Mtce)	2017 target (Mtce) (annual change from 2012)
Beijing	23	10 (-16%)
Chongqing	68	54 (-4.5%)
Guangdong	176	160 (-1.9%)
Hebei	314	274 (-2.7%)
Jiangsu	278	301 (+1.6%)
Jilin	111	100 (-2.1%)
Liaoning	182	142 (-4.8%)
Shaanxi	158	138 (-2.6%)
Shandong	402	382 (-1.0%)
Shanghai and Zhejiang	201	177 (0% for Yangtze River Delta overall)
Tianjin	53	43 (-4%)

Note: Yangtze River Delta includes Shanghai, Jiangsu and Zhejiang.

Source: NDRC, 2015; IEA analysis.

## Natural resource availability

The problem of water scarcity is a growing challenge for energy system planners in China. The impacts of water pollution, increasing water consumption, freshwater withdrawals and expansion of water stress zones are major challenges. Large thermal power plants, whether nuclear, coal or gas, and renewable energy from biofuels and CSP consume large quantities of water. There is a widening gap between water demand and limited supplies and, as a result of widespread pollution, water quality is deteriorating, particularly in the North.

In the 12<sup>th</sup> FYP, targets were established to cut water consumption per unit of value-added industrial output by 30% and water-related concerns are felt across China's energy sector. China has plans to construct desalination plants as it seeks to secure water supplies for many of its coastal cities, including Tianjin and Qingdao. As desalination is an energy-intensive process for water production, expansion of this technology will increase the demand for energy. Additionally, while coastal projects that incorporate saltwater cooling will offset the need for fresh water, water treatment and energy storage facilities will further impact China's water energy resource challenge. Electricity choices will also impact water requirements differently (Table A.1.2). For example, a coal plant using tower cooling (also called closed cooling) with CCS may increase water consumption by 50% to 110% per MWh compared to an unabated coal plant (Macknick et al, 2012; Meldrum et al, 2013). However, because dry cooling is a viable option for the whole power plant or the capture plant alone, increases in water consumption can be avoided at the expense of a modest efficiency penalty.

Table A.1.2. • Typical water consumption values for a selection of power generation technologies

Technology	Water withdrawals (litres per MWh)
Hydro	5 400 – 68 100
Coal with CCS (subcritical, tower cooling)	3 400 – 3 600
CSP (trough)	2 800 – 4 200
Coal with CCS (supercritical, tower cooling)	3 000 – 3 400
Nuclear (tower cooling)	2 200 – 3 200
Coal without CCS (supercritical, tower cooling)	1 700 – 2 200
Natural gas combined cycle without CCS (tower cooling)	500 – 1 100
Coal with or without CCS (dry cooling)	5 - 10
PV and wind	0-1

Note: Values for dry cooling are estimated from the literature.

Source: Macknick et al, 2012.

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## Annex 2 Technical considerations for retrofit of CO<sub>2</sub> capture

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CO<sub>2</sub> capture solutions have been retrofitted to tens of coal-fired power plants worldwide, ranging in scale from pilot projects of around 0.5 MW, such as the Huaneng Beijing Gaobeidian project, up to the 110 MW Boundary Dam plant in Canada. Detailed engineering studies have been conducted for several other large-scale retrofits and these have been made publicly available as part of government funding conditions. In addition, a number of studies of retrofit designs and options have been published by research institutions around the world. This annex draws on the available sources to describe the technical approaches to retrofitting CCS and how they affect the efficiency and operation of a power plant.

The annex describes each of the following topics in sequence:

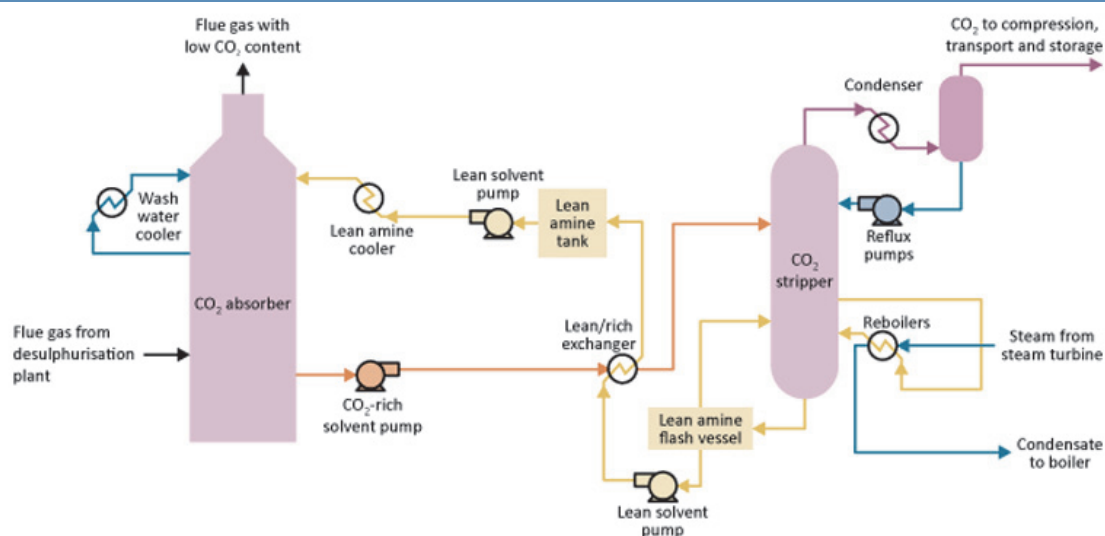
- Simple retrofits: addition of CO<sub>2</sub> capture with minimal modification of the base plant
  - Capital expenditure
  - Energy requirements
  - Space requirements
- Modifications to the base plant that can enable or improve retrofits
  - Pollution controls
  - Boiler and turbine upgrades
  - Oxy-fuel combustion
- Novel and alternative approaches to post-combustion CO<sub>2</sub> capture

### Simple retrofits: addition of CO<sub>2</sub> capture with minimal modification of the base plant

The simplest form of retrofit typically involves re-routing the flue gas from a unit's boiler through a CO<sub>2</sub> capture facility. For a coal-fired plant, flue gas typically contains between 12% and 14% CO<sub>2</sub> by volume. After separation of the vast majority of this CO<sub>2</sub> in the CO<sub>2</sub> capture facility, the remaining gases (mostly nitrogen and water vapour) are emitted to the atmosphere via the flue gas stack or cooling tower. The CO<sub>2</sub> is compressed to pipeline pressure and piped offsite to be transported for use or storage. This process is known as post-combustion capture, because CO<sub>2</sub> is separated from flue gases at the end of the power generation process. Because it leaves the rest of the power generation cycle largely untouched, it is most suitable for retrofits.

The current industry standard for separating CO<sub>2</sub> from the flue gases of a power plant is amine solvent absorption. This requires two main vessels, a CO<sub>2</sub> absorber and a CO<sub>2</sub> stripper (Figure A.2.1). In the CO<sub>2</sub> absorber, the flue gas comes into contact with the aqueous amine solvent and CO<sub>2</sub> is absorbed into the solvent. The commercially optimal proportion of CO<sub>2</sub> that is absorbed is usually considered to be 90% to 95% using today's solvents. Separation of higher percentages is technically feasible but requires more energy and larger equipment. In the CO<sub>2</sub> stripper, heat is applied to the solvent in the form of steam to the point at which the CO<sub>2</sub> is liberated in a pure form. The solvent is then recycled to the CO<sub>2</sub> absorber and topped up as necessary. Cooling, usually provided by the power plant cooling water circuit, is needed to cool the CO<sub>2</sub> fed to the absorber, condense out solvent from the CO<sub>2</sub> before compression, and cool CO<sub>2</sub> during compression.

**Figure A.2.1 • Schematic of a post-combustion CO<sub>2</sub> capture facility**



Source: IEA, 2015.

Steam supplied to the CO<sub>2</sub> stripper is typically taken from the power plant steam turbine. A steam pressure of around 4.5 bar is considered ideal for today's solvents in order to minimise energy losses (Lucquiaud et al, 2009).<sup>27</sup> The appropriate location for extraction of this steam is generally the crossover pipe between the intermediate and low pressure turbines. The steam removed from the turbine is steam that would otherwise have contributed to electricity generation. Because less steam is available for electricity generation as a result of operating the CO<sub>2</sub> capture facility, CO<sub>2</sub> capture reduces the gross electricity generation of the power plant unit. Compression of the CO<sub>2</sub> for transport off-site uses electricity from the power plant generators to run the compressors, and electricity is also used by fans and pumps within the capture plant, which further reduces the net electricity output of the plant.

The reduction in net electricity output of a coal-fired power plant unit retrofitted with CO<sub>2</sub> capture using this approach is around 20% to 30%. Thus, a 600 MW unit would be de-rated to an output of around 480 MW, or less, of low-carbon electricity after retrofitting with CCS.

Before flue gas can enter an amine-based CO<sub>2</sub> capture facility it must have SO<sub>2</sub> content below 10-100 ppm because SO<sub>2</sub> can poison the solvent (Bailey and Feron, 2005). For this reason, plants that do not already have highly effective FGD systems need to install one at the time of CCS retrofit.

Partial retrofits of power plant units are possible by bypassing the CO<sub>2</sub> capture facility with a fraction of the total flue gas. The result is a unit with higher CO<sub>2</sub> emissions intensity than a full retrofit. If the target is to match the emissions intensity of a CCGT, only around two thirds of the flue gas needs to pass through the CO<sub>2</sub> capture facility, resulting in a capture rate below 50%. For each ten percentage points that the capture rate is reduced below 90%, the investment costs and incremental LCOE each decrease by around 10%, not accounting for CO<sub>2</sub> transport and storage (NETL, 2007). However, lower capture rates lead to higher emissions per kWh and the costs per unit of CO<sub>2</sub> mitigated rise by around 5% for each ten percentage points that the capture rate is reduced below 90% due to economies of scale.

<sup>27</sup> If steam is extracted from the turbines at a pressure higher than around 5 bar, it can be modified using a back pressure turbine (see below).

## Flexibility

The flexibility of fossil fuel power plant operation – which has traditionally helped to balance the variability of electricity demand – has increased in recent years, partly in response to the expansion of variable renewable electricity sources. There has been some concern that post-combustion CO<sub>2</sub> capture may reduce the flexibility of power plants because of slower start-up times of the solvent regenerator compared with the turbines, limited turndown ratio of the CO<sub>2</sub> compressors, and uncertainty about whether CO<sub>2</sub> transport and storage infrastructures can accept intermittent CO<sub>2</sub> streams. However, modelling work has shown that the flexibility of CCS-equipped power plants would not necessarily be limited with appropriate adjustments to design (Cohen, Rochelle and Webber, 2011; Lucquiaud, Chalmers and Gibbins, 2007). Flexible CCS retrofits could bring major benefits to electricity grids by providing low-carbon dispatchable power, and to operators by enabling them to earn revenue during more hours, including times of high electricity prices.

Constraints on the efficient turndown of CO<sub>2</sub> compressors can be overcome by use of multiple trains of equipment. CO<sub>2</sub> losses during start-up can be limited by appropriate design of equipment and control schemes. Fast dynamics for load following as well as fast shutdowns can be achieved without additional CO<sub>2</sub> losses. This flexible operation now needs to be verified and optimised in large power plants.

Furthermore, post-combustion CO<sub>2</sub> capture retrofits could even increase operational flexibility. The capture unit, which consumes substantial amounts of steam and power, could be bypassed or turned down to rapidly increase the net power output by up to around 25%, which is not possible for a plant without CO<sub>2</sub> capture unless it is running at part load. A CCS retrofit will continue to have a grid connection sufficient for the full output of the base plant before retrofit. The economics of this option would be determined by the cost of incorporating these capabilities and penalties associated with increased emissions of CO<sub>2</sub> during these periods of providing balancing services.

There are other options for more flexible operation without increased emissions, which could be attractive depending on any emission penalties and grid needs. One option is to capture the CO<sub>2</sub> as normal but to delay the energy-intensive process of regenerating the solvent, and separating then compressing the CO<sub>2</sub>, until times of low power demand and prices. The additional capital costs for the extra solvent and storage of the CO<sub>2</sub>-laden solvent would be greater than those that would enable bypass of the capture plant.

As with thermal generators today, there are always additional costs associated with load-following and ramping operation, for example due to reduced material lifetimes and lower efficiencies at part load. Today, investments in open cycle gas turbines continue to be made despite having low expected operating hours and efficiencies well below those of combined-cycle gas turbines (CCGTs). This is because costs can be recovered during variable times of operation – usually peak prices – and because absolute capital expenditure is low.

## Capital expenditure

The capital cost items for a retrofit of post-combustion CO<sub>2</sub> capture (with de-rating of the power plant) are:

- CO<sub>2</sub> capture facility, including CO<sub>2</sub> absorber, CO<sub>2</sub> stripper, pumps and pipework
- Minor modifications to steam and electricity integration
- Compressors
- Any major modifications, including addition of FGD, turbine modifications or boiler upgrades

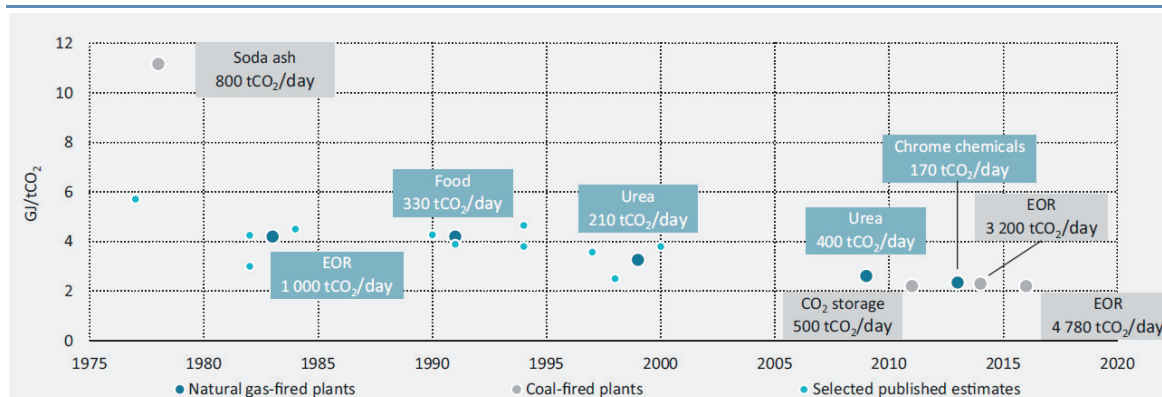


CO<sub>2</sub> capture using amines is not a new technology. However, the challenge of deploying this established commercial technique for reducing emissions from large facilities such as power plants is a challenge of scale-up and cost reduction. In the process of scaling up SO<sub>2</sub> and CO<sub>2</sub> capture solutions, for example, Shell Cansolv reduced capital costs without compromising performance by using concrete as the material for the absorber tower instead of steel (Shaw, 2012). This is an example of how innovation is driving cost reductions in CCS. SaskPower, the operator of the Boundary Dam plant, has stated that they have learned enough through the construction and operation of the first retrofit to be able to reduce the costs of a second project by up to 30% (Monea, 2015).

## Energy requirements

CO<sub>2</sub> separation technologies for post-combustion capture are relatively mature because they were developed as a source of CO<sub>2</sub> for the food and chemicals sectors and, later, EOR. Amine solvent absorption has recently been significantly improved for application as a climate change mitigation technology. New solvents and better plant integration have helped reduce the energy required to separate CO<sub>2</sub> from flue gas by 50% since 1990 (Figure A.2.2).

Figure A.2.2 • Improvements in CO<sub>2</sub> separation energy for post-combustion capture



Note: GJ<sub>th</sub>/tCO<sub>2</sub> = gigajoules of thermal energy per tonne of CO<sub>2</sub> separated.

Source: IEA, 2015.

CO<sub>2</sub> capture has a significant energy cost because of the low partial pressure of CO<sub>2</sub> in power plant flue gas and the high pressures needed for CO<sub>2</sub> transport and storage. For amine solvent absorption, the main energy-consuming step in the process is the regeneration of the solvent and the recovery of the pure CO<sub>2</sub> after it has been chemically captured. Specifically, energy is required to: heat the solvent, the majority of which is water; liberate the CO<sub>2</sub> from the solvent to which it is chemically bound; and circulate the solvent. The additional requirements for amine-based systems are typically 0.4 gigajoules of electrical energy per tonne of CO<sub>2</sub> captured (GJ<sub>e</sub>/tCO<sub>2</sub>) for compression to 11 MPa and up to 0.1 GJ<sub>e</sub>/tCO<sub>2</sub> for other needs, generally delivered as electricity (Thambimuthu, 2005). The minimum energy requirement for compression from 0.1 MPa to 15 MPa is 0.24 GJ/tCO<sub>2</sub> (Feron, 2009).

The level of efficiency of the base plant, contrary to intuition, is not necessarily a decisive factor in determining suitability for retrofitting. For two otherwise identical coal-fired plants with different efficiencies – for example, a subcritical and a supercritical plant – receiving the same price for their electricity, the cost of CO<sub>2</sub> avoided<sup>28</sup> would be very similar (Lucquiaud and Gibbins,

<sup>28</sup> Potentially, this could be the CO<sub>2</sub> price at which a CCS retrofit would break even if the CO<sub>2</sub> pricing policy were sufficiently robust to trigger investment.

2011). This is because the amount of energy required to capture and compress one tonne of CO<sub>2</sub> is nearly identical between the two plants. The retrofitted subcritical plant will avoid the emission of more CO<sub>2</sub> per MWh, assuming equal capture rates and fuel sources but will incur higher capital costs – probably in proportion to the additional CO<sub>2</sub> that would need to be captured per MW of capacity – and would suffer from lower efficiency, greater reduction in capacity and less revenue from electricity sales in a competitive market.

Detailed studies of CO<sub>2</sub> capture retrofit options for four U.S. coal-fired power plants constructed in the 1970s and 1980s showed consistent reductions in HHV efficiency of around 30% to 35% and reductions in capacity of 25% to 35%. These plants, with capacities ranging from 129 MW to 1 800 MW, were not directly correlated between base plant efficiency and the magnitude of the efficiency reduction, due to other site-specific factors such as coal quality, presence of pollution controls and turbine pressure (Dillon et al, 2013a).<sup>29</sup>

While CO<sub>2</sub> separation energies using amine solvents may be approaching an energetic limit just below 2 GJ<sub>th</sub>/tCO<sub>2</sub>, the overall energy penalty can be reduced by improved thermal integration. This can be achieved by recovering heat from the CO<sub>2</sub> stream leaving the stripper column after solvent regeneration and from the CO<sub>2</sub> compressor intercoolers and used for condensate heating. This replaces steam that would otherwise be taken from the low pressure turbine and can compensate partly for the lower steam flow to the low pressure turbine as a result of the retrofit. Experts have expressed views that limiting efficiency losses to around 22% (for example, a reduction from 43% generation efficiency to 34% efficiency) by 2025 is a reasonable expectation (Jenni, Baker and Nemet, 2013).

Just as it is reasonable to expect that the performance of post-combustion capture will improve between 2015 and 2025, solvent improvements can also be expected after a CO<sub>2</sub> retrofit has been undertaken. Thus, it may be important that the retrofit design does not risk precluding the adoption of higher performing CO<sub>2</sub> capture innovations in the future. A technical recommendation is that CCS retrofits should be able to accommodate the use of a range of steam pressures and temperatures for future improved solvents (GHG IA, 2013).

Post-combustion CCS can also be retrofitted to natural gas-fired power plants, leading to a reduction in the efficiency of a combined cycle gas turbine (CCGT) plant from 57% to 50% using current technology (Dillon et al, 2013b).

### Space requirements

The total land needed to accommodate a CO<sub>2</sub> capture facility, including compressors, has been estimated by different studies to range from 300 to 800 m<sup>2</sup> per MW retrofitted for units of 300 MW to 600 MW (Florin and Fennell, 2010; GCCSI, 2010; NETL, 2007). This footprint is around ten times larger per MW than an FGD facility and is similar in scale to a unit's turbine hall and boiler combined. Some space savings could be made by retrofits of multiple units or larger units due to shared utilities and scaling effects for some equipment. These savings would be greater if the design of the power plant was optimised for integration of CO<sub>2</sub> capture from the outset (i.e. CCS ready).

Available engineering studies for mature CCS retrofit projects suggest that this range may be high. Front end engineering and design studies for the Longannet and Kingsnorth power plants show space requirements for CO<sub>2</sub> capture and compression of around 200 m<sup>2</sup> and 150 m<sup>2</sup> per MW for retrofits of 300 MW units (E.ON UK, 2011; ScottishPower, 2011). The higher figure for

<sup>29</sup> Good base plant efficiency was found to be a good indicator of a lower CO<sub>2</sub> capture penalty but this is partly because less efficient plants tend to have steam cycle designs that incur higher losses when CO<sub>2</sub> capture is integrated and not because efficiency itself is a determining factor.

Longannet is due to the planned addition of a gas turbine to supply the heat to the CO<sub>2</sub> stripper so that de-rating of the plant could be avoided. In both cases, additional space would be required for the construction of the plant and routing of pipework and utilities.

## Modifications to the base plant that can enable or improve retrofits

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Many of today's installed units would require some modification to improve their compatibility with CO<sub>2</sub> capture facilities and to extend their operational life to provide several decades of low carbon electricity output. Such modifications could involve large items such as upgrades to the turbine and pollution control equipment, rebuilding the boiler and modifications to allow for closer heat integration between the capture plant and steam cycle. More extensive modifications to enable a retrofit might include conversion of the boiler to oxy-fuel combustion or the construction of an external heat source, such as a natural gas-fired CHP plant. The extent of these modifications is a site-specific consideration. They can be minimised by integrating CO<sub>2</sub> capture into the original design of the unit (i.e. CCS ready).

It may be strategically valuable to undertake other plant upgrades concurrently with the CCS retrofit project in order to take advantage of the outages (periods when the unit is not available to generate electricity) caused by the process of integrating CO<sub>2</sub> capture. Outages of one to three months might be assumed for undertaking the connection for a full retrofit of CCS equipment if the equipment itself can be constructed while the power plant operates uninterrupted.

To minimise loss of revenue during the retrofitting process, two-stage retrofits can take advantage of outages that are planned for other upgrades during a plant's operational life. For example, a routine maintenance outage may be an attractive opportunity to undertake other modifications that would make the plant CCS ready in anticipation of future completion of the retrofit process. This approach would limit the length of time and the cost of the later retrofit project itself and therefore improve the economic attractiveness of the CCS retrofit. The up-front costs of these advance modifications could perhaps achieve immediate commercial benefits in terms of a better-defined cap on the plant owner's future liability for CO<sub>2</sub> emissions charges.

### Pollution controls

As noted earlier, plants that do not already have highly effective FGD systems would need to install one to prevent SO<sub>2</sub> from entering an amine-based capture system. The most effective FGD systems are so-called "wet" systems, which can remove up to 98% of SO<sub>2</sub> from flue gases using limestone or lime reagents. Standards for SO<sub>2</sub> removal in China are as high as those in other parts of the world (Table A.2.1), which has led to wide adoption of wet FGD systems. This gives Chinese plants an advantage over some older plants in other parts of the world. For example, the retrofit of Boundary Dam Unit 3 in Canada involved the addition of an entirely new FGD system.

Table A.2.1. • Coal power plant emissions standards in China, the EU and the United States

	China	EU	U.S.
	(mg/m <sub>3</sub> )	(mg/m <sub>3</sub> )	(mg/m <sub>3</sub> )
<b>SO<sub>2</sub></b>			
Existing plants	400	400	160 – 640
New plants	35 - 100	200	160
<b>NO<sub>x</sub></b>			
Existing plants	400	200 – 500	117 - 640
New plants	35 - 100	200 – 500	117
<b>Dust/particulate</b>			
Existing plants	400	50	22.5
New plants	35 - 100	50	22.5

Note: NO<sub>x</sub> = nitrogen oxides.

Source: BNEF, 2015.

### Boiler and turbine upgrades

As discussed above, a CCS retrofit can be a good opportunity to upgrade other elements of a power plant unit, such as the boiler and turbine. Not only will such upgrades raise the efficiency of the CCS-equipped plant, but they can also extend the lifetime of the plant if it is approaching the final decades of its design life. The result can be a flexible low carbon generator with thirty or more years of life, at a lower cost than a new low-carbon power plant. The retrofit of Boundary Dam Unit 3 in Canada involved boiler modifications and replacement of the old steam turbine with a new state-of-the-art turbine. Newer plants, and plants designed to be CCS ready, may not require such modifications, however.

A specific consideration for retrofitting a unit with CO<sub>2</sub> capture is the impact of steam provision. Unless steam is provided by an external source (see next section) the pressure at which steam can be extracted from the turbines will determine the design of the heat integration and the overall impact on electricity output. Turbines from which steam cannot be extracted at the ideal pressure may need to be complemented by equipment to adjust the steam pressure between the turbines and the CO<sub>2</sub> stripper. For units with higher steam pressures between the intermediate and low pressure turbines than are needed for CO<sub>2</sub> stripping, there are several options: throttling valves to restrict the steam flow through the low pressure turbine; addition of back-pressure turbines; and re-blading of the last stages of the intermediate pressure turbine. Among these options, the use of back pressure turbines is associated with the smallest loss in electrical output (Lucquiaud and Gibbins, 2011). Depending on site-specific conditions, the low-pressure stage of the LP steam turbine may also need to be rebuilt in order to be able to handle the lower low-pressure steam availability.

### External heat sources

It is not always necessary to reduce the electrical output of the retrofitted unit, especially if there is a preference for maintaining the prior full capacity of the plant as a low-carbon generator. In this case, steam cannot be taken from the unit's turbines but must be provided by an external source. In addition, to maintain (or increase) the overall output of the plant, electricity also needs to be supplied from an external source, which could be the grid. An option that can supply both of these needs is an additional CHP plant located nearby.

The retrofit of a 250 MW unit at the WA Parish coal plant in Texas, United States, will take its steam requirements from a newly built gas-fired CHP plant (NRG, 2014). The CHP plant is a simple cycle 75 MW natural gas-fired turbine that entered operation in 2013 (three years before the CCS-equipped plant is due to commence operation), the exhaust from which will be passed through a steam generator to provide for the capture system. Energy not needed for CO<sub>2</sub> capture can be sold to the grid at times of high electricity demand or supply shortage, due to the flexibility advantages of a single cycle turbine.

If heat is supplied from an external source, the CCS retrofit, including this auxiliary plant, has the option of increasing its output above its pre-retrofit capacity. As discussed above, a post-combustion CCS plant can bypass the CO<sub>2</sub> capture facility to increase output and operate flexibly. This can have high value to the grid, but can come with costs related to policies that discourage increased emissions rates, depending on the policy environment. If the CO<sub>2</sub> capture facility is bypassed and the auxiliary CHP plant is operated, the total output will be higher than for other types of retrofits.

Whether to de-rate the power plant by removing steam from the turbine, or maintain output by using an auxiliary steam source, is largely a matter of economics and local drivers. It will depend on the capacity needs of the grid, the space on site and the opportunity costs of the higher capital investment. Above all, it may depend on the access to natural gas supplies because, given the likely CO<sub>2</sub> emissions constraints that would trigger the CCS retrofit, it is highly improbable that the auxiliary source could be coal-fired and deliver the necessary overall emissions reduction.

Several studies comparing these options have found de-rating to be more cost-effective (GHG IA, 2011). Furthermore, auxiliary plants can introduce economic uncertainty due to the plant's operating profit dependence upon natural gas prices (Bashadi and Herzog, 2011). Only in cases with relatively low natural gas prices have auxiliary plants been found to make retrofits potentially more affordable.

### ***Oxy-fuel combustion***

In oxy-fuel combustion processes, the fuel is burnt in oxygen rather than air. The resulting flue gas is primarily CO<sub>2</sub> and water. Some of the flue gas is recycled to the combustion process to maintain the proper ratio of fuel to oxygen, and the remainder is dehydrated and compressed for transport and eventual storage. Oxy-fuel combustion avoids the needs for a post-combustion CO<sub>2</sub> capture facility and therefore avoids the need to extract steam from the turbine. However, large volumes of oxygen are needed for combustion, which requires an air separation unit (ASU) that is larger than the sizes of ASU that are commercially offered today for other industrial applications. Thus, while lower unit costs of oxygen production may emerge from R&D directed towards large ASUs for oxy-fuel, the early projects are likely to use multiple ASUs at currently available sizes. ASUs require electricity as an energy input, which is provided as auto-consumption of part of the gross output of an oxy-fuel power plant, thus reducing net output and giving rise to an efficiency penalty of similar magnitude to post-combustion systems.

Retrofitting oxy-fuel combustion is possible, but requires more plant modifications than post-combustion capture. Ideally, the boiler should be replaced with one that can tolerate the higher flame temperatures<sup>30</sup> and prevent ingress of air into the combustion chamber. A flue gas condenser is also required, as well as additional pipework for circulation of gases. Much of the additional footprint of an oxy-fuel retrofit is from the ASU, which is powered by electricity.

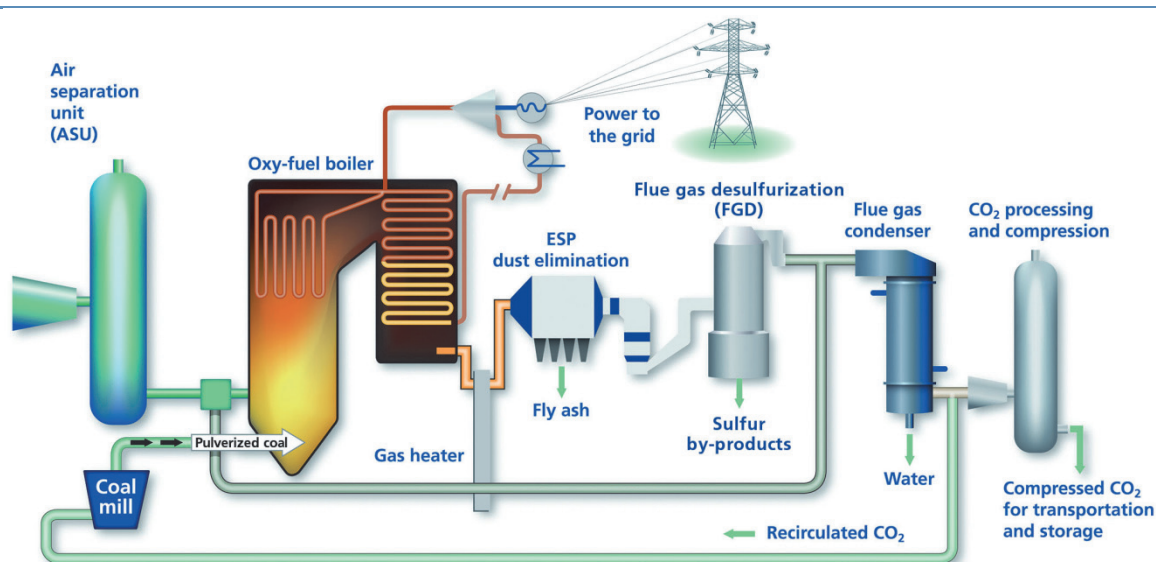
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<sup>30</sup> In practice, the CO<sub>2</sub> recycle rate can be adjusted to the temperature tolerance of the boiler, but this has an impact on efficiency.

Oxy-fuel combustion has been successfully operated at scales of 30 MW but few larger projects are in advanced stages of planning. The FutureGen 2.0 project in Illinois, United States, was intended to be as a retrofit of a 40-year old oil-fired 200 MW unit and was scheduled to begin operation in 2017 (U.S. DOE, 2013). The design included replacement of the boiler, construction of an ASU and construction of CO<sub>2</sub> purification and compression units. The original steam turbine was to be maintained due to its good condition; the plant has operated mostly in peaking mode during its lifetime, including only 900 starts. The overall power rating of the plant would have been reduced to 99 MW, after auto-consumption of around 69 MW of the gross output (FutureGen Alliance, 2014). However, federal government funding was withdrawn from the FutureGen project in February 2015, as it had missed important project milestones. This makes the project unlikely to proceed.

An oxy-fuel project was also one of two large-scale CCS projects competing for government funding in the UK. The White Rose project involved the construction of an entirely new 290 MW unit, which was to use only the existing coal handling and utilities infrastructure from the neighbouring 4 GW coal and biomass-fired power station. A schematic diagram is shown in Figure A.2.3. However, the UK funding competition was cancelled in fall of 2015 and, hence the project is unlikely to proceed.

Figure A.2.3 • Schematic diagram of oxy-fuel combustion as planned for the White Rose project, UK



Source: Alstom 2014

## Novel and alternative approaches to post-combustion CO<sub>2</sub> capture

While amine solvents will continue to contribute some improvements, potential alternatives for post-combustion CO<sub>2</sub> capture exist that could go beyond the promise of more advanced amine systems (Aldous et al., 2013; GHG IA, 2014; SINTEF, 2013). These alternatives differ in the particular cost elements of current technologies that they seek to reduce, such as capital costs, desorption energy and compression costs. They are also at different stages of development (Table A.2.2). Since none of these technologies is clearly superior, some research organisations and governments are taking a prudent and balanced portfolio approach by investing in multiple



options. Balanced portfolios include technologies representing both lower-risk, incremental improvements and higher-risk, more profound improvements.

**Table A.2.2 • Non-exhaustive list of advanced post-combustion CO<sub>2</sub> capture technologies and their features**

CO <sub>2</sub> capture type	Key advantages	Potential disadvantages	Experience with power plant flue gas or in other sectors
Advanced non-amine aqueous solvents (e.g. ammonia, piperazine, amino acid salts)	Lower heat demand; leverages experience from amine solvents; lower solvent volatility (piperazine).	Performance improvements may not be large.	Chilled ammonia tested at 20 MW on coal in the United States (2009) and at 20 MW on gas and fluid catalytic cracker in Norway (2012). Piperazine tested at 0.1 MW in United States and Australia. Amino acid salts tested at 2 MW in Australia.
Calcium looping	Low-cost sorbent; spent sorbent may have commercial value.	Make-up stream of sorbent required; pure oxygen input may be needed; retrofits may be poorly optimised.	Tested at 1.9 MW <sub>th</sub> in Taiwan (2013) and at 1.7 MW <sub>th</sub> in Spain.
Catalytic solvent activation, including enzymes	Smaller equipment (advanced absorption kinetics); lower regeneration energy.	Catalyst/enzyme costs (due to deactivation and instability); turnaround issues with immobilized catalysts.	Projects under way to scale up to 0.1 MW <sub>th</sub> in United States by 2016. CO <sub>2</sub> separation for biogas upgrading is more advanced.
Cryogenic fractionation	No hazardous chemicals; no impact on steam cycle (uses electrical energy); CO <sub>2</sub> delivered at close to pipeline pressure; potentially lower separation energy.	High equipment costs.	Proof of concept stage for post-combustion.  Used extensively for separating gases from natural gas and air. Under development for CO <sub>2</sub> separation from natural gas.
Biphasic liquid solvents	Lower regeneration energy (no water in solvent regeneration); smaller equipment and solvent volumes; lower solvent degradation.	Additional equipment needed for phase separation; higher solvent costs; process design/scale-up uncertainties (rich-phase viscosity presents technical challenges).	Carbamate-forming amine tested at approx. 0.005 MW <sub>e</sub> scale in United States (2014). DMX-1 demixing solvent tested at bench/mini-pilot scale in Europe (2013).
Hybrid membrane/absorption, membrane/cryogenic	Lower separation energy; pre-treatment with membranes could reduce capital and solvents costs.	Trade-off between additional complexity and potentially incremental gains compared to single technologies; process design/scale-up uncertainties (e.g. material degradation challenges).	Membrane/cryogenic tested on coal at 0.1 MW anticipating 0.3 MW in United States in 2015. Already used to separate CO <sub>2</sub> during hydrogen production at commercial scale in Europe.  Membrane/absorption tested at lab-scale; projects under way to scale up to 0.005-0.025 MW <sub>e</sub> in United States by 2016.
Membranes	Smaller equipment (high contact areas); no hazardous chemicals; modular (possible incremental retrofits); no impact on steam cycle (uses electrical energy); high turndown ratios possible.	Often need an additional purification step; process design/scale-up uncertainties (equipment yet to be proven at sufficient scale); trade-off between CO <sub>2</sub> purity and capture rate.	Tested at 1 MW in United States (late 2014). Tested at 0.05 MW <sub>th</sub> in Europe (2011).  Used for CO <sub>2</sub> separation from natural gas since the 1980s.

Non-aqueous solvents	Lower regeneration energy (no water in solvent regeneration); lower solvent volatility; smaller equipment (high CO <sub>2</sub> loading).	High solvent cost; process design/scale-up uncertainties (high viscosity of rich phase and water balance maintenance).	Scale-up of imidazole-amine hybrids to 0.5 MW anticipated in United States in 2015. Ionic liquids tested at bench scale.
Precipitating solvents	Reduced regeneration energy; smaller equipment (higher driving force for absorption); lower solvent degradation.	Increased solvent costs; need to handle solids; process design/scale-up uncertainties (novel equipment needed for absorbers with slurries).	Potassium carbonate system tested at ~0.05 MW in Australia. Scale-up of carbamate solvent to 0.5 MW anticipated in United States in 2015.
Pressure swing adsorption (PSA) and vacuum swing adsorption	No hazardous chemicals; no impact on steam cycle (uses electrical energy); smaller equipment (rapid PSA cycles); simple and flexible operation.	Trade-off between CO <sub>2</sub> purity and capture rate; pressure drop may limit efficiency.	Tested at bench scale. Used extensively and commercially for CO <sub>2</sub> separation in natural gas processing.
Supersonic inertial CO <sub>2</sub> extraction system	No hazardous chemicals; smaller equipment; low system volume.	High electrical demand for flue gas compression; need to handle solid CO <sub>2</sub> ; process design/scale-up uncertainties (slip gas minimisation); uncertainty regarding load following ability.	Proof of concept stage, aiming for scale-up to 0.25 MW <sub>th</sub> in United States by 2016.
Temperature swing adsorption (TSA) and electric swing adsorption	No hazardous chemicals; lower water demand; high purity CO <sub>2</sub> stream (compared to PSA); potentially fast kinetics and lower heat requirements.	Sorbent attrition/deactivation; high sorbent requirements; process design/scale-up uncertainties (e.g. heat recovery from solids and pressure drops).	Tested at 10 MW scale using potassium-based sorbent in Korea in 2014. Scale-up of TSA with alumina adsorbents and solid sorbent-supported amines to 0.5-1 MW is under way in the United States. Used commercially for CO <sub>2</sub> separation in natural gas processing.

Note: MW<sub>th</sub> = megawatt thermal. MW scales of experience are indicative and in several cases derived from equivalent CO<sub>2</sub> or flue gas mass flows.

Source: IEA, 2015.

Processes that capture CO<sub>2</sub> from flue gases by incorporating CO<sub>2</sub> into minerals or algae could also be developed in the coming decades. Unlike those listed above, these processes do not deliver CO<sub>2</sub> as a gas for storage but produce materials that could be sold for fuel or construction materials. While there may be commercial advantages to such CO<sub>2</sub> “utilisation” approaches, understanding the associated emissions reduction is more complex if the use of the resulting material might lead to release of the CO<sub>2</sub> to the atmosphere (Bennett, 2014). Mineralisation and algal capture approaches are currently at an early stage of development for post-combustion applications and face considerable challenges related to achieving power plant scales of operation (Sanna et al, 2014; GHG IA, 2014).

Research is also focusing on processes and techniques that could bring down the costs of existing solvent systems, which could also benefit the technologies in Table A.1.2. For absorption systems, these techniques could include: membrane pre-treatment, novel dispersion/mass transfer equipment, absorber intercooling, stripper inter-heating, flashing, multi-pressure stripping, electrochemically mediated regeneration, computational tools for system integration. The benefits in terms of efficiency improvements will need to be weighed against possible increases in complexity and capital costs. Both improved solvents and new processes may require heat at different temperatures, pressures or steam volumes. Thus, upgrading a CCS-equipped power plant to use an improved solvent may require modification to the integrated CO<sub>2</sub> capture

and power plant system. Further work is required to understand trade-offs between static optimisation and future-proofing of concepts.

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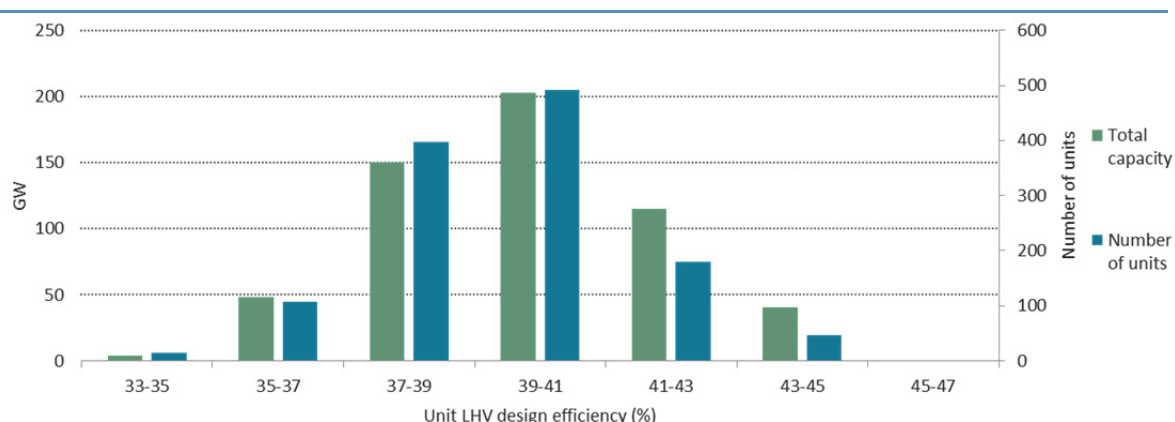
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## Annex 3 Characteristics of CEC power plant units that influence CCS retrofit costs

### Page | 80 Efficiency

CEC plants, due to their recent average construction, have high design efficiencies for coal-fired power plants. While not all units are operated at their optimum efficiency level, due to operating at part-load or the use of coal with lower energy content, design efficiency is an indication of which units would have the lowest operating costs if retrofitted with CO<sub>2</sub> capture. 190.3 GW (34.0%) of CEC capacity has a design efficiency of 41% or more. This is a total of 290 units (Figure A.3.1).

Figure A.3.1 • Distribution of efficiencies of CEC units



Notes: LHV = low heating value. Design efficiencies are calculated on the basis of boiler efficiency, turbine heat rate, coal type and cooling type for each unit. Potential efficiencies after retrofitting are based on an efficiency penalty of 9 percentage points.

### Steam conditions

The pace at which China has built power plants since 2004 has resulted in considerable standardisation of design. This is different from the plants built longer ago, which generally seem to have different layout designs (Li, 2010). The steam conditions of subcritical units are less ideal for amine solvent regeneration and have crossover pressures between low pressure and intermediate pressure turbine cylinders higher than 11 bar. However, Chinese ultra-supercritical plants often have pressures closer to the ideal pressure of 4 to 5 bar, according to data from CEC. Crossover pressures for 600 MW supercritical units are generally around 10.4 bar and those for 600 MW ultra-supercritical units are generally around 4.9 bar. The most efficient 1000 MW units, such as Waigaoqiao No. 3, can have crossover pressures as low as 1.1 bar as a result of optimisation work to raise design efficiency to 46%.<sup>31</sup>

Retrofits of subcritical and supercritical plants can be achieved without significantly larger energy penalties through either the upgrading of the boiler and turbine or, more cost effectively for newer plants, by addition of back pressure turbine with a dedicated generator (Lucquiaud, 2011). These options require capital investments that would not be required for a retrofit of a large

<sup>31</sup> It should be noted, however, that steam conditions reported in the literature vary, see Duan et al., (2014) and Xu et al., (2011). Furthermore, as CO<sub>2</sub> capture technology evolves, the ideal steam pressure for avoiding energy losses may also be adjusted.



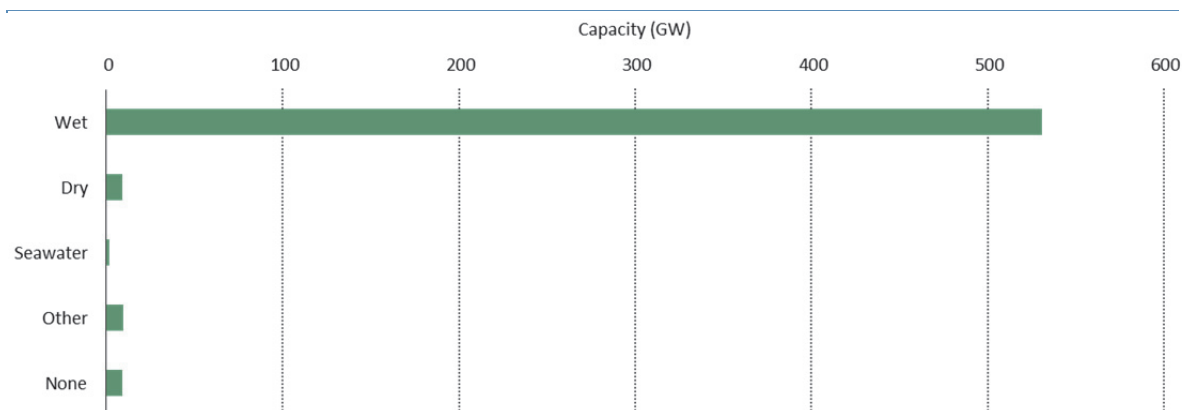
ultra-supercritical unit, making them less attractive. Nonetheless, retrofit of a unit with non-ideal steam conditions is likely to remain more attractive than retirement of the unit and replacement by a new CCS-equipped ultra-supercritical unit.

## Desulphurisation

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Wet desulphurisation technology is the most effective for the removal of SO<sub>2</sub> from power plant flue gas. 530.6 GW (94.8%) of CEC capacity has wet FGD technology installed. This is a total of 1170 units (Figure A.3.2). These plants would have lower costs for the retrofit of CO<sub>2</sub> capture as additional equipment to reduce SO<sub>2</sub> would not be required.

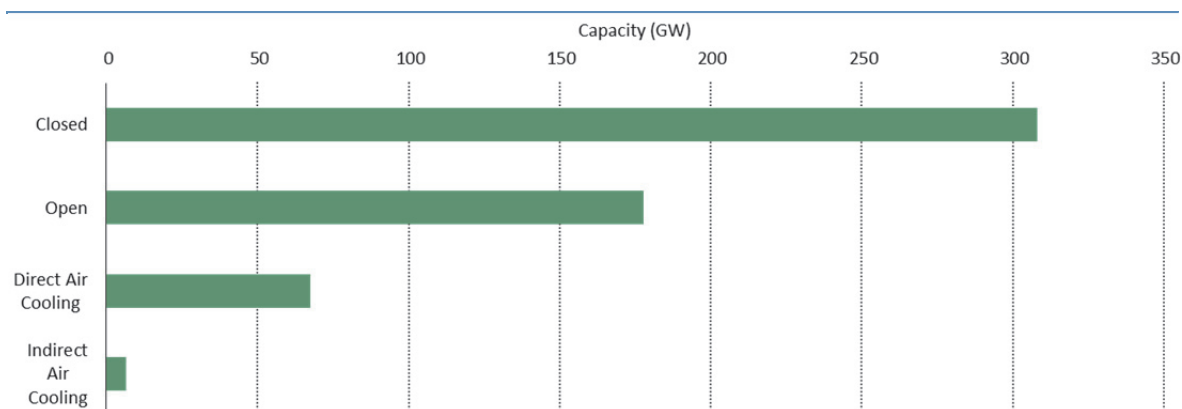
**Figure A.3.2 • Distribution of desulphurisation types for CEC units**



## Cooling

All other things being equal, plants with tower or open cooling systems will be cheaper to retrofit and plants with dry (air) cooling systems will be more expensive. 485.8 GW (86.8%) of CEC capacity has tower or open cooling technology installed. This is a total of 1077 units (Figure A.3.3).

**Figure A.3.3 • Distribution of cooling types for CEC units**



## Space on site

It is not uncommon for Chinese power plants to be located close to the industrialised or populated areas that they serve. Three factors can make retrofit projects in these areas more challenging:

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- The space on which to construct the CO<sub>2</sub> capture facility may not be available due to the proximity of neighbouring operations, or geographical limits to expansion.
- The land in developed areas may be of much higher value than land in less developed parts of the region and thus costly to procure for construction of the CO<sub>2</sub> capture facility.
- The pipeline route for exporting the CO<sub>2</sub> to the storage site may be complicated and require a higher investment of time and resources to reach completion.

A previous analysis used a non-quantitative survey of satellite image searches to look at space requirements and drew the following conclusions (Li, 2010):

- Plants in rural locations have a better prospect of having sufficient space to locate CO<sub>2</sub> capture units that are big enough to capture CO<sub>2</sub> from the whole plant.
- Most plants have the potential for at least a partial retrofit, i.e. retrofitting a proportion of the generating units at a given plant.
- Plants in more developed areas have the least potential to be retrofitted in the future.

The plants that were found to have a low chance of retrofitting due to space constraints were 46% of the 74 plants evaluated (GHG IA, 2011). However, the study did not consider how space availability might develop over the coming two decades.

It is not possible in the scope of the present study to look at the space availability for each of the 1 236 units analysed and estimate how this might evolve over the next two decades. Nevertheless, space constraints appear to be a factor that will in practice mean that the total number of plants in China that are suitable for retrofit will be lower than the theoretical number presented in this study.

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## Annex 4 CCS Retrofit Cost and Performance

A performance-cost model was developed to provide an indication of relative costs of retrofitting CEC units that were found to be suitable candidates. To the extent possible, the model takes into account the different attributes of CEC units and how these attributes would affect retrofit costs. As discussed elsewhere in this paper, retrofit costs will be influenced by the size, efficiency, presence of FGD, proximity to suitable storage and any plant modifications to extend the lifetime of the unit after retrofit.

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### Cost components and metrics

Bohm (2007) and Dillon (2013) summarize cost components that are likely to be encountered when retrofitting post-combustion capture to an existing pulverised coal power plant:

- Capture equipment, including CO<sub>2</sub> absorber and stripper columns, blowers, pumps and ductwork.
- CO<sub>2</sub> compressors and pumps.
- The low-pressure stage of the steam turbine may need to be rebuilt in order to be able to handle the lower low-pressure steam availability, unless additional steam is provided from an alternative source.
- The stringent sulphur level limits of amine solvents may require addition of (or an upgrade to the existing) flue gas desulphurisation (FGD) equipment, which will, in turn, further decrease net electricity output due to higher auto-consumption of electricity.
- Additional space for the CO<sub>2</sub> separation and compression system.
- Increased cooling water requirements – for direct cooling of the flue gas before introduction to the absorber and possibly in order to generate additional steam.

In addition, the cost of transporting and storing CO<sub>2</sub> will depend on the distance of transport, the terrain and the geology of the storage site.

The cost metric used for this study is levelised additional cost of electricity (LACOE). It is similar to the levelised cost of electricity (LCOE) in that it is an approximation of the revenue per unit of net electricity output required for the power project to deliver a specified return on investment over the life of the asset. However, LACOE considers only the additional costs related to the retrofit, including capital costs of capture and all associated modifications and operational costs such as fuel and CO<sub>2</sub> transport and storage. LACOE does not capture the value of adding capture to reduce CO<sub>2</sub> emissions costs, but it is a useful guide for comparisons between similar units on a common basis in the absence of detailed market parameters.

The LACOE represents the premium that an operator would need to receive per unit of electricity generated in order to recover the additional costs of producing low-carbon electricity instead of electricity with high emissions of CO<sub>2</sub>. To move from the LACOE to an estimation of the actual LCOE of an individual unit after retrofitting would require additional data that is likely to vary substantially from unit to unit. Additional data needs for a calculation of post-retrofit LCOE include the value of the underlying power plant asset, which would take into account its cost at the time of construction and depreciation in the years of prior to the retrofit decision. Alternatively, such data could be used alongside an estimate of future power prices to estimate the premium that would deliver a return-on-investment equal to that obtained by continuing to operate the existing asset. LACOE is a convenient way to avoid these uncertain data requirements.

## Key assumptions

For the purposes of this analysis, certain basic assumptions have been made about the nature of the retrofit.

- Fuel input to the plant remains constant, as does the duty of the steam cycle condenser (Lucquiaud and Gibbins, 2009); thus, the net output of the plant falls with the addition of a capture system.
- The capture system is an absorption solvent-based system, similar to current state-of-the-art designs for CO<sub>2</sub> separation. The energy requirements for CO<sub>2</sub> capture and compression are primarily driven by heat demand (around 60%) rather than electricity demand (around 40%).
- Steam requirements for the capture system are obtained from the steam turbine intermediate to low pressure crossover. Supply of steam from an external source has not been contemplated.
- The capture system has a capture rate that is sized to process the flue gas from the entire unit and operated at its design point for the remaining lifetime of the retrofitted unit.
- Should an FGD not be present, we include the cost of adding an FGD to the plant alongside the retrofit.
- We consider two options for the addition of capture: the plant can be retrofitted at minimum cost, in which case the retrofitted plant can operate until the end of the original plant's lifetime; or, the plant can be rebuilt with CCS, in which case the boiler is refurbished and deeper modifications are made that extend the plant lifetime and improve heat integration between the capture system and steam cycle.

## Methodology

The first step in estimating the LACOE is to assess the performance of the retrofitted (or rebuilt) unit. Following this, regression equations are used to estimate the engineering, procurement and construction (EPC) cost of the retrofit (or rebuild). Process and project contingencies are added to arrive at the total plant cost (TPC), which is then inflated to account for owner's costs (e.g., insurance, royalties, inventories of catalysts or chemicals) to arrive at total overnight costs (TOC) (Rubin, Davison and Herzog, 2013). The construction time and discount rate are then used to convert the TOC to the total capital requirement (TCR), which is the principle input to the LACOE.

### Estimation of efficiency penalty

The model provides a quantitative estimate of the electrical output penalty resulting from diverting steam from the steam cycle to the CO<sub>2</sub> stripper re-boiler, compression (and pumping) of the CO<sub>2</sub> for delivery at pressure, and auxiliary loads (e.g. solvent pumping, blowers) in the capture system. It also accounts for the increased load resulting from an FGD unit, should the plant not be equipped with FGD. The model assumes, however, that space exists (or can be created) for the CO<sub>2</sub> capture system and that surplus cooling capacity exists that can absorb the increased cooling duty.

The post-retrofit net output,  $P'_{net}$ , is given by:

$$P'_{net} = P_{gross} - P_{BOP} - P_{FGD} - P_{cool} - P_{reb} - P_{cap}$$

Nameplate (net) capacity of units, their boiler efficiency and steam cycle heat rates on an LHV basis, cooling system type, coal type, and whether they are equipped with an FGD system is information provided by CEC. The net plant efficiency,  $\eta_{net}$ , is calculated as:

$$\eta_{net} = \eta_{blr} \frac{3600}{\dot{H}_{sc}} \eta_{gen} (1 - p_{FGD} - p_{BOP} - p_{cool})$$

Where  $\eta_{blr}$  is the boiler efficiency;  $\dot{H}_{sc}$  is the steam-cycle heat rate (MJ/MWh). The gross plant output is arrived at by:

$$P_{gross} = \frac{P_{net}}{(1 - p_{FGD} - p_{BOP} - p_{cool})}$$

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Where  $p_{FGD}$ ,  $p_{BOP}$ , and  $p_{cool}$  are efficiency penalties resulting from the balance-of-plant, dry cooling system, and FGD loads. As implied by the above formula, the balance-of-plant (BOP), FGD, and cooling system power consumption – for cases where the plant uses dry cooling – is calculated as a percentage of the gross plant output.

$$P_{BOP} = p_{BOP} P_{gross}$$

$$P_{FGD} = p_{FGD} P_{gross}$$

$$P_{cool} = p_{cool} P_{gross}$$

The approach of Lucquiaud & Gibbins (2011), in which the capture system thermal load is converted to an equivalent electrical load through a coefficient of performance (COP) used to estimate  $P_{reb}$ :

$$\begin{aligned} P_{reb} &= \frac{\dot{Q}_{reb}}{COP} \\ &= \frac{1000 \cdot \dot{m}_{CO_2, cap} e_{rgn}}{3600 \cdot COP} \\ &= \dot{m}_{CO_2, cap} \left( \frac{1000 \cdot e_{rgn}}{3600 \cdot COP} \right) \end{aligned}$$

The electrical power requirement for capture auxiliaries is calculated from the energy requirements for the capture system auxiliaries,  $e_{aux}$  (kWh/t), and compression,  $e_{comp}$  (kWh/t):

$$P_{cap} = \dot{m}_{CO_2, cap} \left( \frac{e_{aux} + e_{comp}}{1000} \right)$$

Parameter values for the calculation of the reboiler electrical-equivalent heat duty and capture power requirement are shown in Table A.4.1.

**Table A.4.1. • Reboiler and capture system parameter assumptions**

Parameter	Value	Notes
CO <sub>2</sub> Removal Fraction	0.9	
Regeneration Energy (GJ/tCO <sub>2</sub> )	2.5	Consistent with Shell Cansolv baseline in NETL (2015)
Retrofit COP (MW <sub>th</sub> /MW <sub>e</sub> )	4	Results from NETL (2015) baseline case B12B imply a COP of 3.77, consistent with a relatively high (160-170 °C) regeneration temperature (Lucquiaud & Gibbins, 2011). Assume throttled LP turbine case from Lucquiaud & Gibbins (2009).
Rebuild COP (MW <sub>th</sub> /MW <sub>e</sub> )	4.5	Assume IP & LP stage modifications to allow floating IP-LP pressure (Lucquiaud & Gibbins, 2009)
Compression Requirements (kWh/tCO <sub>2</sub> )	100	Compression from (near) atmospheric pressure to 150 bar.
Auxiliaries (kWh/tCO <sub>2</sub> )	20	Consistent with Lucquiaud & Gibbins (2011) and comparable to NETL (2015) case B12B.

The mass of CO<sub>2</sub> captured is calculated as:

$$m_{CO_2, cap} = f_o \frac{44 \cdot 3600 \cdot \alpha C_{fuel}}{12 \times 10^6} \dot{Q}_{coal}$$

Where,  $\dot{Q}_{coal}$  is the thermal input to the plant (MW, on an HHV basis),  $\alpha$  is the fraction carbon converted in the boiler, and  $C_{fuel}$  is the emissions factor for the fuel (tC/TJ). The thermal input to the plant is calculated by dividing the pre-retrofit net power output,  $P_{net}$ , is divided by the estimated net efficiency.

### Estimation of retrofit and rebuild capital cost

EPC costs of the capture system, steam turbine modifications, FGD costs, and boiler rebuild are estimated based on power-law scaling rule:

$$C = C_o \left( \frac{A}{A_o} \right)^n$$

Where  $C_o$  is the reference cost at capacity,  $A_o$ , the desired capacity is  $A$ , and  $n$  is the scaling exponent. The values of the scaling exponents for each area were taken from NETL (2013), while the values for  $C_o$  and  $A_o$  were estimated from Rubin et al. (2015) and studies cited therein – in particular NETL (2013), GHG IA (2014) and WorleyParsons and Schlumberger (2011) – through least-squares regression using the linearized version of the scaling rule. All costs in these reports were converted to 2013 USD using the IHS PCCI index, as presented by Rubin et al. (2015). Costs presented in GHG IA (2014) were converted from Euros to 2013 USD and the re-based from US Gulf Coast to Rotterdam using factors provided in WorleyParsons and Schlumberger (2011) before used in the analysis. The resulting regression parameters are listed in Table A.4.2.

**Table A.4.2. • Capital cost regression parameters**

Cost Component	Capture System	Steam Turbine Generator	FGD Costs†	Boiler Island
Co (EPC, 2013 USD)	2.69E+08	1.95E+08	2.18E+08	3.88E+08
Ao	355	8.93E+05	602	1.90E+03
Ao Units	tCO <sub>2</sub> /h (compressor discharge)	kW <sub>e</sub> (gross output)	tCO <sub>2</sub> /h (boiler outlet)	kW <sub>th</sub> (coal input)
n	0.6	0.7	0.6	0.69
Process Contingency (of EPC)	10%	0%	0%	0%
Project Contingency (of EPC+Process)	30%	30%	30%	30%
Retrofit Replacement Fraction		10%		0%
Rebuild Replacement Fraction		50%		50%

Note: FGD costs are based on a "system only" cost of 280 USD/kW as reported by Sharp (2009) for 600-900 MW units, scaled to a 750 MW supercritical plant.

Process and project contingencies are added to the EPC costs to arrive at the TPC:

- A 10% process contingency, which is used to quantify the additional capital costs that will likely arise as a process matures into a full-scale commercial technology, was added to the capture system.
- A 30% project contingency was added to all other cost categories to account for the low level of definition of the cost estimate and that these are retrofit applications where additional



complications are likely to arise. For comparison, NETL (2013), GHG IA (2014) and WorleyParsons and Schlumberger (2011) generally use only a 10% project contingency.

All TPC costs are inflated to overnight costs (TOC) with the addition of 15%, and TOC costs to TCR costs by adding interest accrued during construction. It is assumed a retrofit can be accomplished in one-year of construction, while a rebuild requires two years of construction time. A discount rate of 9% is assumed.

## Calculation of LACOE

LACOE is calculated as:

$$LACOE = \frac{fcf \cdot C_{TCR} + C_{FOM}}{8766 \cdot P_{net} \cdot CF} + \frac{3600(P_{reb} + P_{cap})}{1000 \cdot \eta_{gross}} c_{fuel} + m_{CO_2, cap} C_{T\&S}$$

Where  $fcf$  is the fixed charge factor (Rubin et al., 2013);  $C_{TCR}$  and  $C_{FOM}$  are the plant capital cost and annual fixed operations and maintenance (O&M) cost (USD);  $CF$  is the annual capacity factor;  $c_{fuel}$  is the fuel cost (USD/GJ); and,  $C_{T\&S}$  is cost of transport and storage (USD/tCO<sub>2</sub>) for the captured CO<sub>2</sub>.

Assumptions required for the calculation of LACOE are provided in Table A.4.3.

**Table A.4.3. • Power plant assumptions for calculation of LACOE**

Cost item	Assumption	Value
Discount Rate		9%
Decision Timing	Retrofit decision made in 2030, at the mid-point of the period under study 2025 to 2035	2030
Operational lifetime	Retrofitted units are operated to the end of their 40 year lifetime. Retrofits with rebuild have a life extension of 40 years from the date of retrofit.	
Incremental fixed operating and maintenance costs	Incremental FO&M costs are incurred only on new elements added to the plant.	3% of TPC
Fuel costs	Coal costs taken from IEA WEO 450 climate change mitigation scenario for 2030, with upwards or downwards adjustment for each province	Average of 2.9 USD/GJ
CO <sub>2</sub> transport and storage cost	The costs of CO <sub>2</sub> transport and storage are calculated on the basis of the lowest cost option for each unit as described in Annex 5.	USD/tCO <sub>2</sub> values vary with each unit.

## Calculating representative Chinese values

The US Gulf Coast capital costs estimated from equations presented in Table A.4.2. using a conversion factor of 0.61 – implying that a CO<sub>2</sub> capture plant built in China costs 61% of the cost of the same plant built in the United States. This factor was estimated from the regional indices for capital, material, and labour costs combined with the corresponding capital cost breakdown for CO<sub>2</sub> capture and compression for a pulverized coal power plant presented in WorleyParsons and Schlumberger (2011). The China based costs in 2013 USD were converted to CNY using the average 2013 average exchange rate of 0.16 USD per CNY.

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## Annex 5 CO<sub>2</sub> storage site assessments

A methodology for assessing the availability of CO<sub>2</sub> storage for power plant retrofits was developed to answer the following questions:

- For each power plant unit, which storage site would offer the lowest combined costs of CO<sub>2</sub> transport and storage?
- How do these results change if constraints are placed on the maximum distance over which CO<sub>2</sub> can be transported?
- If multiple units were retrofitted, how might competition between them for the lowest-cost storage options affect the suitability of individual units to be retrofitted?

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In this Annex the methodological steps that were followed to answer these questions are detailed. This starts with how storage sites are defined and their suitability and capacity is assessed. This is followed by a description of how the technical parameters for CO<sub>2</sub> transport and storage are coupled with economic data to yield cost estimates and how competition is assessed.

The method broadly follows that which is outlined by Dahowski et al. (2009, 2012) and Wei et al. (2013). In this study, uncertainty is further reduced in comparison to earlier work as more detailed geological information and detailed techno-economic models are now available (Wei et al., 2016; Wei et al., 2015a). The methodology uses sub-basin/basin scale geological data, current field experience and estimates of representative economics. It is a first step toward understanding how CO<sub>2</sub> storage sites and CCS retrofits might be paired under prevailing economic and policy conditions. There is scope for future improvements to the analysis through more specific geological surveys and increased differentiation between local conditions, especially above the surface.

### Storage site suitability evaluation

Selecting a suitable CO<sub>2</sub> storage site for a CCS project can be a time- and data-intensive process. This is because the level of detail needed to ensure that the geological conditions in a given area can ensure safe and permanent CO<sub>2</sub> containment is rarely available at the beginning of the process. This is especially true for saline aquifer storage resources that have often not been explored in detail for their CO<sub>2</sub> retention properties, whereas for many oil and gas fields extensive data have already been gathered from surveys and samples. Thus identifying a site often begins with using existing data to identify the most promising geological basin, then the most suitable sub-basin scale region and, finally, more detailed investigation and quantitative analysis of several specific sites (NETL, 2010).

This study uses site suitability results from a sub-basin scale evaluation, following the method in Wei et al. (2013). This evaluation of CO<sub>2</sub> aquifer storage was performed using a process based on spatial analysis in geographic information system (GIS) software and multi-criteria methods considering geological characteristics, geological and geographical risk factors, environmental constraints and economic land use factors. A weighted suitability metric was assessed for each of 54 794 storage units representing distinct, contiguous areas of 0.0495 latitude by 0.0495 longitude. Sites with a suitability score of 0.24 or above (one a scale from zero to one) were considered to have some suitability for CO<sub>2</sub> storage and were included in the analysis.

For each suitable site, storage capacity for each storage unit was estimated as a function of its area, thickness, porosity, density and a storage efficiency factor following the method outlined by Goodman et al., (2011):

$$G_{CO_2} = A \cdot h_g \cdot \varphi_{tot} \cdot \rho_{CO_2} \cdot E_{saline}$$

$G_{CO_2}$  = mass estimate of CO<sub>2</sub> storage resource

$A$  = geographic area defining the region being assessed for storage

$h_g$  = gross thickness of the saline formation being assessed within the region

$\varphi_{tot}$  = total porosity of the assessed formation volume

$\rho_{CO_2}$  = density of CO<sub>2</sub> evaluated at storage conditions

$E_{saline}$  = total CO<sub>2</sub> storage efficiency factor that reflects the fraction of the total pore volume that can be expected to be filled by CO<sub>2</sub>, it is calculated as follows:

$$E_{saline} = E_{An/At} \cdot E_{hn/hg} \cdot E_{\varphi_e/\varphi_{tot}} \cdot E_v \cdot E_d$$

$E_{An/At}$  = net-to-total area ratio; the fraction of the total basin or region area that is suitable for CO<sub>2</sub> storage

$E_{hn/hg}$  = net-to-gross thickness ratio; fraction of the total geologic unit that meets minimum porosity and permeability requirements for injection

$E_{\varphi_e/\varphi_{tot}}$  = effective-to-total porosity ratio; fraction of total interconnected porosity

$E_v$  = volumetric displacement

$E_d$  = microscopic displacement

In this study,  $E_{saline} = 0.024$  at 50% confidence level for suitable aquifer storage sites, as per other studies (NETL, 2012; GHG IA, 2009).

The result of this evaluation is a database of potential storage units in China and their attributes in terms of capacity, porosity, permeability and other factors that influence the economics of CO<sub>2</sub> storage.<sup>32</sup>

## Techno-economic considerations

For a given retrofit, the most suitable CO<sub>2</sub> storage site can be identified by minimising the combined costs of CO<sub>2</sub> transport and CO<sub>2</sub> storage. Thus, trade-offs between distance and storage efficacy can be incorporated. For a given quantity of CO<sub>2</sub> to be stored, performance models for transport and storage at each site can be coupled with cost models (McCoy, 2008, 2009).

### CO<sub>2</sub> storage

The performance of a CO<sub>2</sub> storage operation at a given site is a function of a variety of factors, including the number of injection wells to be drilled and operated and the number of pressure control or water production wells. The number of injection wells is highly dependent on in-situ reservoir pressure, thickness, depth, permeability and maximum injection pressure. For saline aquifer storage, multiple injection and control wells are assumed to be used at each site to limit the migration region of CO<sub>2</sub> and maximise use of pore spaces underground. The ratio of CO<sub>2</sub> injection wells to pressure control wells is assumed to be 1:0.5. The maximum injection pressure is assumed to be 125% of the hydro-static pressure in reservoir.

<sup>32</sup> Representative values for thickness and permeability are assigned at a basin scale to each deep saline formation-bearing basin (Dahowski, 2012).

Performance parameters, such as the number of required wells, are translated to capital expenditure (CAPEX) and operational expenditure (OPEX) values. CAPEX of CO<sub>2</sub> storage includes the costs of site characterisation and evaluation, well drilling and completion, CO<sub>2</sub> flow-line and connections, injection equipment, water production equipment, and water desalination equipment. Operations and maintenance (O&M) costs include the costs of well operations, well maintenance, daily site maintenance activities, storage monitoring and verification and water desalination, among others.

### CO<sub>2</sub> transport

CO<sub>2</sub> is assumed to be transported onshore via pipeline as supercritical CO<sub>2</sub>, which is considered to be cost-effective at the relevant scales and surface temperatures of power plant retrofit projects and locations in China. Performance parameters for transport of a given volume of CO<sub>2</sub> between two points are a function of CO<sub>2</sub> properties (e.g. pressure, temperature, pressure drop) and pipeline parameters (e.g. diameter, material strength, length). To mitigate unrealistically low costs for pipelines crossing inhospitable terrain, altitudes, urban centres or waterways a factor of 1.17 was applied to the straight distance between two points to represent a more realistic pipeline distance.

Costs evaluation is based on the techno-economic model by Wei et al. (2016) and economic parameters from the reports by the Economic and Technology Research Institute of China Petrochemical Group (Zhou, 2012). In addition to the transportation scale and length of pipeline, CAPEX is influence by a location and a topographic factor. The location factor of 0.8 and the topographic factor of 1.0 used in this study are average factors for China.

### Identifying the lowest-cost storage option for each unit

For each unit, the storage site with the lowest combined cost of CO<sub>2</sub> transport and storage is considered to be the preferred site. It was found by comparing of the costs for each feasible grouping of adjacent storage units in the dataset that in total could provide sufficient storage capacity for the retrofitted unit.

The following assumptions were made:

- Any suitable storage site or site group (several adjacent sites), which matched by a retrofitted unit, would need to accommodate CO<sub>2</sub> captured from the retrofitted unit over a period of at least 20 years.
- The retrofitted units would capture 90% of the current emissions from the unit, the output of which would be de-rated due to extraction of steam from the turbine to operate the capture plant.
- A maximum allowable transport distance of 1 000 km (costs for maximum allowable transport distances of 250 km and 800 km were also calculated).
- Load factors were assumed to be the same as the 2012 to 2013 average and no changes to the design efficiency or coal type were assumed.

### Analysing competition for CO<sub>2</sub> storage sites

To explore whether competition for storage sites could affect the results, a simulation was performed in which no two power generation units could envisage CO<sub>2</sub> storage in the same storage site unit. The objective was to provide insight into the extent to which overall costs of

CO<sub>2</sub> transport and storage increase due to the effects of competition and the extent to which potential retrofit targets might be “stranded” without access to storage due to competition.

For this analysis, the subset of CEC units that meet the basic criteria for CCS retrofitting was used. The estimates of CO<sub>2</sub> transport and storage costs for each unit-storage site pair were evaluated and fed into a competitive, resource-constrained, least-cost optimization model for determining which retrofitted units may access which specific storage sites. Pairs with the lowest total costs were given first priority, with more costly projects subsequently having an opportunity as long as sufficient storage capacity remained. This methodology broadly follows the methodology of the Battelle CO<sub>2</sub>-GIS model (Dahowski, 2012).

To explore the extent to which CO<sub>2</sub> may need to be transported further, or potential retrofits may become “stranded” without access to CO<sub>2</sub> storage, in a competitive environment, the model was run using three different maximum allowable transport distances: 250 km, 800 km, and 1 000 km.

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# Acronyms, abbreviations and units of measure

## Acronyms and abbreviations

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2DS	2-Degree Scenario (IEA)
4DS	4-Degree Scenario (IEA)
6DS	6-Degree Scenario (IEA)
ACCA21	China's Administrative Centre for Agenda 21
ADB	Asian Development Bank
ASU	air separation unit
BNEF	Bloomberg New Energy Finance
CAPEX	capital expenditure
CAS	Chinese Academy of Sciences
CCGT	combined-cycle gas turbine
CEC	China Electricity Council
CHP	combined heat and power
CNOOC	China National Offshore Oil Corporation
CNY	Chinese Yuan renminbi
CCS	carbon capture and storage
CO <sub>2</sub>	carbon dioxide
CO <sub>2</sub> -EOR	carbon dioxide for enhanced oil recovery
CSLF	Carbon Sequestration Leadership Forum
CSP	concentrating solar power
DDPP	Deep Decarbonisation Pathways Project
DECC	Department of Energy and Climate Change (UK)
ECBM	enhanced coal-bed methane recovery
EEPR	European Energy Programme for Recovery
EOR	enhanced oil recovery
EPC	engineering, procurement and construction
ETP	Energy Technology Perspectives
EWR	enhanced water recovery
FGD	flue gas desulphurisation
FYP	five-year plan
GCCSI	Global CCS Institute
GIS	geographic information system
IEA	International Energy Agency
IEAGHG	IEA Greenhouse Gas R&D Programme
IGCC	integrated gasification combined cycle
IPCC	Intergovernmental Panel on Climate Change
INDC	Intended Nationally Determined Contribution
LACOE	levelised additional cost of electricity
LCOE	levelised cost of electricity
LNG	liquefied natural gas
LHV	low heating value
MHI	Mitsubishi Heavy Industries
NDRC	National Development and Reform Commission (China)
NEA	National Energy Administration (China)
NETL	National Energy Technology Laboratory (US)
NOx	nitrogen oxide

NPS	New Policies Scenario (IEA)
NPV	net present value
OPEX	operational expenditure
O&M	operation and maintenance
PRC	People's Republic of China
PV	photovoltaic
R&D	research and development
SNG	synthetic natural gas
TCR	total capital requirement
TOC	total overnight cost
TPC	total plant cost
UNFCCC	United Nations Framework Convention for Climate Change
USD	United States Dollar
WEO	World Energy Outlook

## Units of measure

### TO BE COMPLETED

bbl	barrels of oil
Bbbl	billion barrels of oil
/d	per day
EJ	exajoule
gce	grams of coal equivalent
GJ	gigajoule
Gt	gigatonne
GtCO <sub>2</sub>	gigatonnes of carbon dioxide
GW	gigawatt
kWh	kilowatt-hour
MW	megawatt
MWh	megawatt-hour
mg	milligrams
Mt	million tonnes (megatonne)
MtCO <sub>2</sub>	megatonnes of carbon dioxide
MW	megawatt
PM	particulate matter
t	tonne
tce	tonnes of coal equivalent
TWh	terawatt-hour
µm	micrometre
/yr	per year

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Layout in France by IEA, May 2016