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IEAGHG Technical Report
2020-08
August 2020

Future Role of CCS Technologies in the Power Sector

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The report should be cited in literature as follows:

'IEAGHG, "Future role of CCS technologies in the power sector", 2020/08, August 2020'.

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FUTURE ROLE OF CCS TECHNOLOGIES IN THE POWER SECTOR

Key Messages

- Carbon capture and storage (CCS) technologies are **essential** for meeting global temperature targets **at least cost**. With power, as with the other sectors, the technologies have the ability to decarbonise but deployment rates are currently far '**off track**'. To meet the targets required to mitigate temperature rises effectively, it is important to understand the specific role CCS technologies can play.
- Power CCS technologies can fulfil different operational roles. As **low-carbon, dispatchable plants**, they can operate at baseload, provide necessary security of supply and system strength services, and are also able to operate flexibly, i.e. they can ramp up and down to operate effectively at lower loads, for example.
- Significantly, as intermittent renewable technologies gain further traction, the ability of CCS plants to **operate flexibly** at lower loads will allow them not only to complement output from intermittent renewables but also to facilitate increased capacity of intermittent renewables on the grid.
- CCS technologies may be used in conjunction with bioenergy (**BECCS**) to provide **net-negative** emissions. They may also be utilised to **sustainably produce hydrogen** from coal, natural gas and biomass, where the hydrogen may then be used in several sectors including power generation.
- The main drivers behind the **evolution of a power market** in a country or region are the extent of its domestic fossil fuel resources, its economic growth and its environmental regulations or ambitions.
- Most regional power CCS outlooks focus on **coal and gas CCS options** operating mainly at **high load factors**[1]. The IEA's Sustainable Development Scenario[2] (SDS) projects a global coal and gas CCS capacity of 320 GW by 2040, divided roughly equally between coal and gas CCS technologies and working at around 68% load factor.
- A **techno-economic analysis** was undertaken to establish the likely roles of CCS technologies in the 4 study regions, **Australia**, **China**, the **UK** and the **United States**. Carbon prices were used to represent a wide range of potential policy incentives. CCS options for **baseload**, **mid-merit** and **peaking** operations were considered, as well as the case for retrofit.
- Results suggest that:
    - Globally **BECCS**, **gas CCS** and **hydrogen** are viable options for baseload, mid-merit and peaking generation, respectively.
    - **Hydrogen** power generation is the lowest cost low-carbon option for flexible backup generation for sustained periods (>8 hours) of high demand, complementing **batteries** which are cheaper for shorter periods.
    - **Gas CCS** is likely to be one of the most economic mid-merit and baseload technologies, even in regions without domestic resources due to its lower costs than alternatives.

[1] In this study, operation at 'high load factors' or 'close to baseload' implies operation at load factors higher than 60%.

[2] www.iea.org/reports/world-energy-model/sustainable-development-scenario.

- **BECCS** is expected to be a strategic technology for climate targets due to its negative emissions, thus it is expected to be deployed in all regions to a certain extent, even if it is not the lowest-cost CCS option.

- A **progressive transition** from coal power plants to BECCS may present an attractive approach to decarbonise in coal-dependent regions.
- Under the modelled assumptions, **increasing CO_2 capture rates to >99%**[3], making plants carbon neutral, may be cost-effective at high load factors.

Background to the study

CCS has long been recognised as a key component of an effective mitigation strategy to decarbonise sectors from power to heating, transport and industry. For many reasons, however, the commercial deployment of CCS has been slow and must accelerate if the technology is to achieve its potential and contribute effectively to mitigating climate change.

Much effort in recent years has been given to improving the technical performance of plants with CO_2 capture, with policy also having a key role to play. Given this background, however, there are just 21 large-scale, CCS plants operating[4] in 8 countries, capturing and storing some 40 million tonnes of CO_2 annually – only two of these plants operate in the power sector.

Scope of Work

With the primary objective to explore the business case for CCS in the power sector, this study examines how the future roles of various CCS technologies are evolving and to consider how their deployment may be enabled in regions with different power markets. In addition to post-combustion coal and gas CCS plants, the study takes in BECCS, hydrogen for power, and retrofitting options. The content is placed in context by focusing on Australia, China, the United Kingdom and the United States and involves the following steps:

- Analysis of recent power sector evolution in each region to identify key drivers;
- Review of power sector outlooks to understand the expected future roles of CCS technologies;
- Techno-economic analysis to determine the competitiveness of different CCS technologies;
- Review of past CCS projects to understand factors underlying their success or failure;
- Identification of CCS deployment challenges and policy recommendations to unlock investment; and
- Collating stakeholder feedback and findings from previous steps to create regional power CCS narratives, including actionable next steps.

The study was undertaken at Element Energy by a team led by Emrah Durusut.

[3] A recent IEAGHG study, "IEAGHG, 'Towards zero emissions CCS in power plants using higher capture rates or biomass', 2019/02, March 2019", suggests that theoretically CCS capture rates may be increased to above 99% from the commonly assumed cap of 90% to eliminate all residual emissions arising from the carbon content of the fuel, resulting in a 7% higher LCOE.
[4] GCCSI database: https://co2re.co/FacilityData.

Findings of the Study

Regional power markets and CCS outlooks

Domestic fossil fuel resources, economic growth and environmental impact are the main drivers behind evolution of power markets. High economic and electricity growth rates, rapid and ongoing urbanisation and industrialisation, and cheap domestic coal have driven China's investment into a large and young coal fleet. Power demands in the other regions (Australia, the UK and the United States) are relatively stagnant. Environmental concerns are driving-out coal in favour of gas and speeding up renewable energy uptake in the UK. Low-cost shale gas resources are causing coal-to-gas fuel switching in the USA, while Australia experiences high domestic natural gas prices, where the price is determined by export commitments and international markets.

Most regional power CCS outlooks only focus on coal and gas CCS options operating close to baseload[1]. The SDS[2] projects a global coal and gas CCS capacity of 320 GW by 2040, divided roughly equally between both technologies and working at ~68% load factor. Two thirds of all coal CCS generation is expected to be just from retrofitted plants in China, while the USA alone has 61% share of the total global gas CCS power generation. Similarly, CSIRO's power outlooks[5] for Australia include a 7-17 GW gas CCS fleet running at 65%-82% load factors by 2050. On the other hand, the 'Net Zero' report[6] for the UK views CCS as essential and includes a wide variety of CCS applications in its future power model. By 2050, the UK is expected to source 23% of its power from baseload and mid-merit gas CCS, while a small 5 GW BECCS fleet is expected to run continuously to maximise negative emissions. Lastly, the UK scenario includes a sizeable peaking hydrogen power capacity to provide backup.

Likely roles of CCS technologies

To better understand the evolving roles of CCS technologies in each region, a techno-economic analysis was conducted by comparing the levelised cost of electricity[7] (LCOE) of each CCS option, with counterfactual technologies, such as unabated fossil plants, nuclear and battery storage. A carbon price[8] is included in each region to represent a wide range of potential policy incentives.

In the figure below, the key messages from the techno-economic analysis of the four regions are summarised, showing the likely roles of CCS technologies under carbon prices consistent with the SDS. CCS options for baseload, mid-merit and peaking operations were considered, as well as cases for retrofit.

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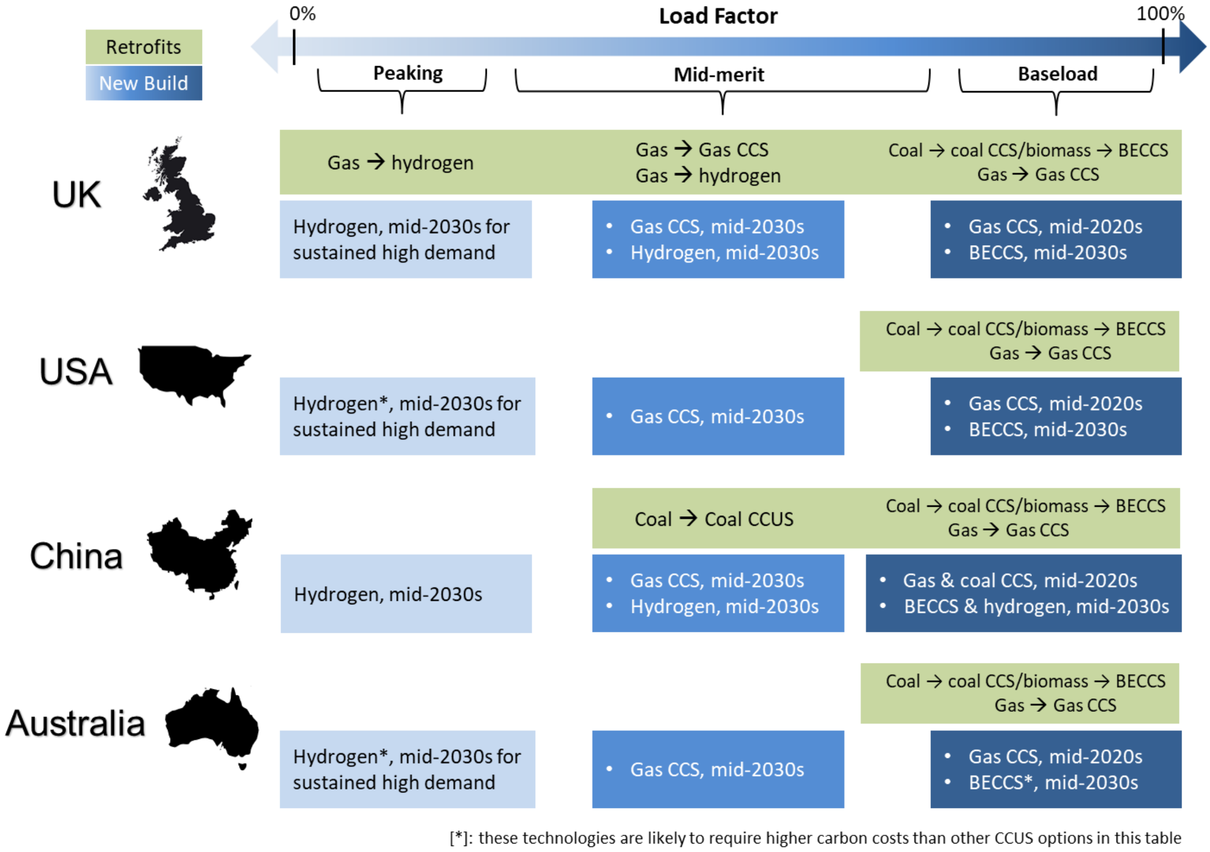
[5] Campey, Bruce, Yankos, Hayward, Graham, Reedman, Brinsmead, Deverell, "Low Emissions Technology Roadmap", Report No. EP167885, CSIRO, Australia, June 2017.

[6] "Net Zero: The UK's contribution to stopping global warming", Committee on Climate Change, UK, May 2019.

[7] The levelised cost of electricity, expressed in £/MWh, is calculated by dividing lifetime costs of a power plant by its total expected generation, discounted to present day. LCOE a common metric used to compare projects of different size, lifetime, technology, etc.

[8] Carbon prices for the USA, China and Australia are from the IEA SDS for developed and developing economies (£32-46/tCO_2 in 2025 and £74-89/tCO_2 in 2035). UK carbon prices are from BEIS Green Book Supplementary Guidance (£44/tCO_2 in 2025 and £111/tCO_2 in 2035).



Globally, BECCS, gas CCS and hydrogen are viable options for baseload, mid-merit and peaking generation, respectively. Hydrogen power generation is the lowest cost low-carbon option for flexible backup generation for sustained periods (>8 hours) of high demand, complementing batteries which are cheaper for shorter periods. However, peaking hydrogen would require a higher support mechanism in the USA and Australia compared to the other two regions due to relatively more expensive hydrogen costs. Gas CCS is likely to be one of the most economic mid-merit and baseload technologies, even in regions without domestic resources due to its lower costs than alternatives. As BECCS offers negative emissions, it is expected to be a strategic technology for climate targets and thus deployed to a certain extent in all regions, even if it is not the lowest-cost CCS option. China is the only region where coal CCS is competitive with other CCS technologies at high load factors and hydrogen power was found to be very cost-effective irrespective of operational mode. The two main reasons for this divergent result for China are the lower-cost domestic coal availability and the option for cheaper hydrogen production through coal gasification.

Natural gas to CCS/hydrogen transition is a viable option in the UK while China has a large coal retrofit potential. Case studies were developed for retrofitting options in the UK and China by calculating the net present value of additional costs and carbon savings associated with conversions. The UK analysis shows that retrofitting peaking or mid-merit gas plants by hydrogen is cost-effective starting from the mid-2030s. On the other hand, gas-to-gas CCS transition is only viable for mid-merit plants. The analysis also indicated that coal-to-coal CCS retrofits in China would be economically justifiable for mid-merit load factors from as early as 2025 under the modelled carbon price assumptions. Noting that China may have as much as

300 GW of retrofittable coal capacity[9], the government would benefit greatly from prioritising actions to realise this potential.

A progressive transition from coal-fired power plants to BECCS may present a valuable approach to decarbonise in coal dependent regions. Drax, the UK's largest power plant, experimented with co-firing biomass before retrofitting 4 of its 6 coal-fired units (each 660 MW) to 100% biomass combustion. Drax is now running a carbon capture demonstration programme with the aim of becoming the world's first large-scale BECCS plant. Although this stepwise transition is facilitated by the UK's coal phase-out plan, other countries with significant coal fleets, including China, the United States and Australia, may consider this model to eventually decarbonise their coal fleets. Moreover, the four countries studied in this report already use at least modest amounts of biomass in electricity generation and re-directing that resource to BECCS could provide some negative emissions with no additional biomass demand.

Increasing CCS capture rates to >99% to make plants carbon neutral may, under the modelled assumptions, be cost-effective at high load factors. A recent IEAGHG study[10] suggests that, theoretically, CCS capture rates may be increased to above 99% from the commonly assumed cap of 90%, to eliminate all residual emissions associated with combustion, resulting in a 7% higher LCOE. The techno-economic analysis undertaken for this study finds that the increased cost of operating at higher capture rates may be offset by carbon-price savings for coal and gas CCS plants operating at baseload and mid-merit load factors. However, the technical feasibility, especially relating to plant flexibility, of operating at high capture rates needs to be studied in greater detail through engineering analysis and practical demonstrations before confidence in this option can be established.

Expert Review Comments

A review was undertaken by a number of international experts. While there were some differences of opinion with views and conclusions drawn from the analysis, these were limited in extent and, on balance, the draft report was very well received.

Comments made related to the use of the levelised cost of electricity to assess the role of CCS-technologies in the power sector. Furthermore, the critical dependence of the conclusions on the regional price of gas and coal and the availability of biomass was highlighted. The appropriateness of the term "baseload" in a power system where all inputs are variable, either by nature or by necessity, was also questioned.

All comments and suggestions made by the reviewers were addressed by the authors. After duly considering each point raised, the authors made corrections and amendments to the text as required.

[9] IEA, "Ready for CCS retrofit: The potential for equipping China's existing coal fleet with carbon capture and storage", Insights Series 2016, May 2016.

[10] IEAGHG, "Towards zero emissions CCS in power plants using higher capture rates or biomass", 2019/02, March 2019.

Conclusions and Recommendations

This study demonstrates the viability of a set of power CCS technologies to cost-effectively decarbonise baseload, mid-merit and peaking generation in distinct power markets. To realise this potential, however, general, technology-specific and country-specific CCS challenges would need to be addressed urgently with policy and regulatory actions.

Realising the potential of CCS technologies requires, without delay, policy incentives to be put in place that will overcome the two main barriers to deployment – high capital expenditure and lack of revenue generation. Economic constraints are at the forefront of CCS related risks and challenges. Projects usually involve very high upfront capital investment (Capex) and, as captured CO_2 is not highly valued, they also lack mechanisms to recover operational expenditure (Opex). The techno-economic model used already assumes a carbon price to represent future incentives, but governments may choose to employ a wide variety of policy mechanisms to create more investable business models for CCS. Some of the major emerging global support mechanisms or actions that can address the market failure that stems from high Capex and Opex are listed in the following table.

High CAPEX	Lack of OPEX Recovery
1. **Capex-based tax credits to alleviate tax liabilities and ease project finance**	1. Operational tax credits to increase profitability
2. **Direct public procurement**	2. CCS obligations with tradeable certificates: each retailer must source a minimum portion of their electricity from CCS power
3. **Capital support through government grants, tax-exempt financing, concessional loans, accelerated depreciation or direct equity investment**	3. Emissions Performance Standards with tradable CCS certificates: each retailer must source a minimum portion of their electricity from low carbon power
4. **Cheaper finance through progressive financing, international financing institutions or export credit agencies**	4. Feed-in-Tariffs (FiTs): plants are paid a fixed amount per unit of electricity produced or CO_2 captured
	5. Contract for Difference (CfD): plants are guaranteed a fixed amount of revenue per kWh or tonne CO_2 stored through topping up spot market prices
	6. Topping up revenues via CO_2 utilisation, e.g. enhanced oil recovery (EOR), carbonated beverages, buildings, plastics and fuels.

In addition to incentives for power generation, incentives must also be developed for CO_2 transportation and storage (T&S) business models. Most CCS projects in the future are likely to use shared T&S infrastructure, which would be managed by dedicated companies. The cost of T&S deployment can be significantly reduced through clustering capture facilities, oversizing initial assets and utilising existing assets that would otherwise be decommissioned. Furthermore, countries can accelerate T&S infrastructure roll-out via public ownership or regulated models which are currently applied to monopoly utilities in some regions.

Individual CCS applications have unique challenges that need to be addressed though targeted incentives and actions in order to enable their deployment at required rates. For example, the main barrier to flexible operation is the fact that currently discussed CCS incentives are designed to reward continuous running and maximised output. Challenges to hydrogen power stem from its dependence on a cross-sectoral shift to a hydrogen economy and several unproven technical capabilities about appliance and grid conversion. Similarly, limitations on BECCS include a general lack of regulation and standardisation of negative emissions, as well as concerns about increased land use for feedstock production. Lastly, retrofitted plants suffer from plant down-time during conversion and efficiency losses during subsequent operation. Apart from the more general mechanisms outlined in the preceding table, some of the common policies and regulations that can overcome technology-specific issues and incentivise CCS technologies are summarised in the table below, along with suggested actions for individual countries.

Each country can assess the globally available policy options to determine actions that best suit their power market and unique circumstances. The table below includes a non-exhaustive list of recommendations to encourage CCS deployment for each of the four countries studied. Countries may want to expand on existing policy mechanisms that are proven to work well, such as Contract for Differences in the UK, tax incentives in the United States and premium wholesale electricity tariffs in China. Furthermore, countries are advised to develop a CCS regulatory regime (China) or improve upon the existing frameworks (the UK, the USA and Australia) focusing on capping CO_2 storage liabilities. In addition, there is an urgency to establish long-term national decarbonisation targets and the development of technology roadmaps for CCS and hydrogen.

Category	Recommendations / Next Steps
Flexible Operation	• Establish capacity markets or include CCS plants in existing markets. • Develop novel policy mechanisms, such as flexible Contracts for Difference, to incentivise CCS plants to run flexibly after intermittent renewables and before unabated fossil plants.
Hydrogen	• Ensure that technical challenges regarding 100% hydrogen turbines are resolved. • Define appropriate business models for the supply-chain producing sustainable hydrogen including use of hydrogen in power generation, taking into consideration carbon footprint accounting and avoiding the double counting of incentives. • Support/incentivise low-carbon hydrogen production, which would indirectly support hydrogen for power. Grid blending, petrochemicals and power have predictable demand and can be early large-scale users for hydrogen deployment.
BECCS	• Develop detailed measurement, monitoring and verification standards for negative emissions. • Recognise and incorporate negative emissions in carbon pricing/accounting systems. • Implement stringent biomass sustainability criteria and help establish sustainable supply-chains. • Promote use of bioenergy with CCS to maximise negative emissions.
Retrofit	• Implement robust "CCS readiness" requirements for all new fossil plants, considering full chain as well as clustering options. Expand these requirements to hydrogen and biomass/BECCS readiness. • Establish unabated fossil fuel-to-CCS transition plans, starting with coal, to incentivise retrofits. • When considering the retrofit potential of plants, use a case-by-case approach rather than having very rigid project decision criteria.

UK	• Encourage future power plants to be in CCS cluster locations. • Expand the current Contract for Difference (CfD) scheme to include CCS and BECCS. • Consider a regulated asset base (RAB) model to deploy CO_2 T&S infrastructure. • Cap post-closure storage liabilities and let storage companies share risks with the government. • Implement further market-based incentives for CCS power companies and a regulated model to deploy T&S infrastructure.
USA	• Harmonise pore space ownership rights in neighbouring states. • Gaps in the incomplete federal CCS regulatory framework needs to be improved. • Cap storage liabilities, especially California Low Carbon Fuel Standard project requirements. • Resolve technical issues preventing coal CCS projects from qualifying for 48A tax credits. • Amend details of 45Q tax credits to encourage more dedicated storage projects than EOR. • Implement further market-based incentives for CCS power companies and a regulated model to deploy T&S infrastructure.
China	• Further develop CO_2 storage resources with state sponsored appraisal projects. • Establish a CCS legal and regulatory framework to guide future projects. • Expand premium national wholesale electricity tariffs of renewables to CCS. • Commit to allocating increased generation hours to initial CCS plants. • Adopt a state-owned/public procurement model for new CCS plants and T&S infrastructure.
Australia	• Announce a long-term[11] emissions reduction target and publish a roadmap to achieve it. • Allow Clean Energy Finance Corporation to invest in CCS. • Establish a scheme such as the Renewable Energy Target for CCS and include BECCS in the Emissions Reduction Fund. • Further emphasise coal gasification and hydrogen power in the national hydrogen roadmap. • Implement further market-based incentives for CCS power companies and a regulated model to deploy T&S infrastructure.

Suggestions for further work

To further assess the role and value of power CCS projects, the following work is recommended:

i. A site-specific analysis of **conversion from coal to biomass co-firing, 100% biomass and BECCS** in the context of coal dependent markets;

ii. A detailed BECCS study investigating the **impacts of biomass supply-chain, costs and life cycle emissions** on future bioenergy potential in each region;

[11] A post-2030 emissions reduction target and a roadmap to at least 2050.

iii. A detailed hydrogen study investigating the **interaction of hydrogen for power with other industries** and the different sources of hydrogen production;
iv. Expansion of the study into **other regions with unique power markets** and geographies such as India, South America, Middle East, Japan and Africa as well as development of a Europe-wide CCS case study focussing on asset sharing and interconnections;
v. **Business model analysis and policy design** dedicated to flexible operation, hydrogen power generation and negative emissions;
vi. Identifying best actions to **improve public acceptance of CCS** considering the unique roles it plays in various regions;
vii. **Wider CO_2 utilisation pathways and coupling of power CCS with other sectors** should be explored through life cycle analysis studies. CO_2 utilisation can provide additional economic benefits (e.g. selling CO_2 to greenhouses and beverage companies), decarbonise hard-to-abate sectors (e.g. synthetic fuels for aviation) and provide grid services such as energy storage;
viii. Tracking the development of **emerging power CCS technologies**, such as pressurised oxyfuel combustion, chemical looping combustion, supercritical CO_2 power cycles (including the Allam Cycle) to determine their potential impact on future power systems.

Of these recommendations, a number have already either wholly or in part been the focus of IEAGHG studies or are currently under investigation.

elementenergy

Global Future Role of Power CCS Technologies

Final Report

IEAGHG

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Acknowledgements

Element Energy would like to extent its special thanks to Keith Burnard (IEAGHG) for his direction and help throughout this study. We would also like to gratefully acknowledge the following people for their input during stakeholder engagement interviews and/or feedback as external reviewers:

- Andrew Feitz (Geoscience Australia)
- Darshak Mehta (Asian Development Bank)
- Dominic Rassool (GCCSI)
- Eric Tenthorey (Geoscience Australia)
- George Booras (EPRI)
- Joe Swisher (EPRI)
- Jonathan Baker-Brian (BEIS)
- Josh Cosgrave (Minerals Council of Australia)
- Karl-Josef Wolf (RWE)
- Karl Smyth (Drax)
- Luke Jones (BEIS)
- Lynn Brickett (US DOE)
- Nick Bevan (BEIS)
- Paul Feron (CSIRO)
- Peter Morris (Minerals Council of Australia)
- Raimund Malischek (IEA)
- Samantha McCulloch (IEA)
- Sarah Forbes (US DOE)
- Stephanie Hutson (US DOE)
- Suzanne Ferguson (Wood)

Finally, we would like to recognise and thank Juho Lipponen (Co-ordinator at Clean Energy Ministerial CCUS Initiative) for his insights and assistance at various stages of the project.

Disclaimer

Executive Summary

Motivation and project overview

Carbon capture and storage (CCS) technologies are essential for meeting global temperature targets because of their ability to decarbonise many sectors from power to heating, transport and industry. However, CCS deployment rates languish far below the required levels. For example, the International Energy Agency's (IEA) Sustainable Development Scenario (SDS) foresees a build rate of 16 GW/year[1] of power CCS between 2020 and 2040, whereas the current installed capacity is only 355 MW. It is therefore important to understand the specific role CCS technologies can play in the power sector.

A variety of power CCS technologies are expected to fulfil different operational roles in evolving timescales. Initial CCS power plants are likely to maximise their generation by operating as baseload plants, but as more intermittent renewable energy is added to the system, CCS may have to work at lower load factors[2] to provide flexibility[3]. CCS may also be used in conjunction with bioenergy (called BECCS) to reach net-negative emissions, where CO_2 absorbed through photosynthesis during plant growth is stored permanently underground. Furthermore, CCS can be utilised to sustainably produce hydrogen from coal, natural gas and biomass. This sustainable hydrogen can then be used in several sectors including power generation.

The aim of this study is to determine the evolving future roles of various CCS technologies and how to enable their deployment in regions with different power markets, focusing on the UK, the USA, People's Republic of China (China) and Australia. In addition to post-combustion coal and gas CCS plants, this study also investigates BECCS, hydrogen for power and retrofitting options. The study consists of the following steps:

- Analysis of recent power sector evolution in each region to identify key drivers.
- Review of power sector outlooks to understand the expected future roles of CCS technologies.
- Techno-economic analysis to determine competitiveness of different CCS technologies.
- Review of past CCS projects to understand factors underlying success or failure.
- Identification of CCS deployment challenges and policy recommendations to unlock investment.
- Collating stakeholder feedback and findings from previous steps to create regional power CCS narratives, including actionable next steps.

Regional power markets and CCS outlooks

Domestic fossil fuel resources, economic growth and environmental impact are the main drivers behind evolution of power markets. High economic and electricity growth rates, rapid and ongoing urbanisation and industrialisation, and cheap domestic coal drive China's investment into a large and young coal fleet. Other regions have stagnant power demands, while environmental concerns are driving-out coal in favour of gas and speeding up renewable energy uptake in the UK. Low-cost shale gas resources are causing coal to gas fuel switching in the USA, while Australia experiences high domestic natural gas prices due to increasing long-term export commitments.

Most regional power CCS outlooks only focus on coal and gas CCS options, operating close to baseload. The IEA Sustainable Development Scenario[1] expects a global coal and gas CCS capacity of 320 GW by 2040, divided roughly equally between both technologies and working at ~68% load factor. Two thirds of all coal CCS generation is expected to be just from retrofitted plants in China, while the USA alone has 61% share of the total global gas CCS power generation. Similarly, CSIRO's power outlooks[4] for

[1] World Energy Outlook 2019. IEA, 2019. Annual build rate includes retrofits.
[2] Load factor is the ratio of a plant's average power output to its maximum possible output.
[3] Flexibility refers to the ability of power plants to ramp generation up and down to balance supply and demand in real time. Flexible plants generally work at lower load factors as they cannot run all the time.
[4] Low Emissions Technology Roadmap. CSIRO, June 2017.

Australia include a 7-17 GW gas CCS fleet running at 65%-82% load factors by 2050. On the other hand, the Committee on Climate Change's Net-zero report for the UK views CCS as essential and includes a wide variety of CCS applications in its future power model. By 2050, the UK is expected to source 23% of its power from baseload and mid-merit gas CCS, while a small 5 GW BECCS fleet is expected to run continuously to maximise negative emissions. Lastly, the scenario includes a sizeable peaking hydrogen power capacity to provide backup.

Likely roles of CCS technologies

To better understand the evolving roles of CCS technologies in each region, a techno-economic analysis is conducted by comparing the levelised cost of electricity[5] (LCOE) of each CCS option, with counterfactual technologies, such as unabated fossil plants, nuclear and battery storage. A carbon price[6] is included in each region to represent a wide range of potential policy incentives.

Figure 1 below summarises the key messages of our techno-economic analysis of 4 regions. CCS options for baseload, mid-merit and peaking operations are considered, as well as certain retrofit case studies.

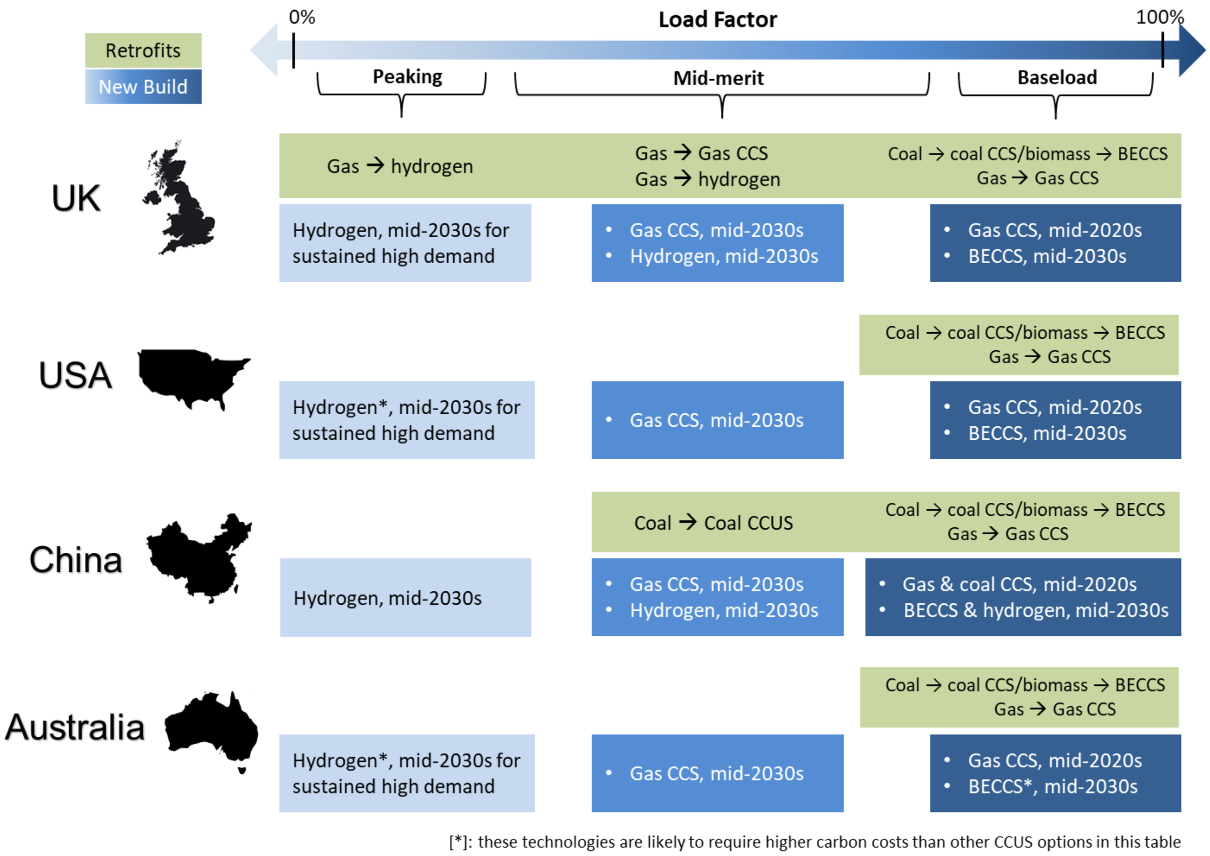


Figure 1: Summary of likely roles of CCS technologies in the 4 study regions under carbon prices consistent with SDS

Globally BECCS, gas CCS and hydrogen are viable options for baseload, mid-merit and peaking generation, respectively. Hydrogen power generation is the lowest cost low-carbon option for flexible backup generation for sustained periods (>8 hours) of high demand, complementing batteries which are cheaper for shorter periods. However, peaking hydrogen would require a higher support mechanism in the

[5] LCOE, expressed in £/MWh, is calculated by dividing lifetime costs of a power plant to its total expected generation, discounted to present day. It's a common metric used to compare projects of different size, lifetime, technology, etc.
[6] Carbon prices for the USA, China and Australia are from the IEA SDS for developed and developing economies (£32-46/tCO_2 in 2025 and £74-89/tCO_2 in 2035). UK carbon prices are from BEIS Green Book Supplementary Guidance (£44/tCO_2 in 2025 and £111/tCO_2 in 2035).

USA and Australia compared to the other two regions due to relatively more expensive hydrogen costs. Gas CCS is likely to be one of the most economic mid-merit and baseload technologies, even in regions without domestic resources due to its lower costs than alternatives. BECCS is expected to be a strategic technology for climate targets due to its negative emissions, thus it is expected to be deployed in all regions to a certain extent, even if it is not the lowest-cost CCS option. China is the only region where coal CCS is competitive with other CCS technologies at high load factors and hydrogen power is very cost-effective irrespective of operational mode. The two main reasons for this divergent result for China are the lower-cost domestic coal availability and the option for cheaper hydrogen production through coal gasification.

Natural gas to CCS/hydrogen transition is a viable option in the UK while China has a large coal retrofit potential. Case studies are developed for retrofitting options in the UK and China by calculating the net present value of additional costs and carbon savings associated with conversions. The UK analysis shows that retrofitting peaking or mid-merit gas plants by hydrogen is cost-effective starting from mid-2030s. On the other hand, gas to gas CCS transition is only viable for mid-merit plants. Our analysis also indicates that coal to coal CCS retrofits in China would be economically justifiable for mid-merit load factors from as early as 2025 under the modelled carbon price assumptions. Noting that China may have as much as 300 GW of retrofittable coal capacity[7], the government would benefit greatly from prioritizing actions to realise this potential.

A progressive transition from coal power plants to BECCS may present a valuable approach to decarbonise coal dependent regions. Drax, the UK's largest power plant, experimented with co-firing biomass in its coal-turbines before retrofitting 4 of its 6 turbines (each 660 MW) to combusting 100% biomass. Now Drax is running a carbon capture demonstration programme with the aim of becoming the world's first large-scale BECCS plant by installing CCS. Although this stepwise transition is facilitated by UK's coal phase-out plan, other countries with significant coal fleets, such as China, the USA, Australia, etc. may consider this model to eventually decarbonise their coal fleets. Moreover, all the countries studied in this report already use at least modest amounts of biomass in electricity generation and re-directing that resource to BECCS can provide some negative emissions without any additional biomass demand.

Increasing CCS capture rates to >99% may cost-effectively make plants carbon neutral at high load factors, under the modelled assumptions. A recent IEAGHG study[8] suggests that theoretically CCS capture rates may be increased to above 99% from the commonly assumed cap of 90% to eliminate all residual emissions associated with combustion, resulting in a 7% higher LCOE. Our techno-economic analysis finds that this increased cost of higher capture rates can be offset by carbon cost savings for coal and gas CCS plants operating at baseload and mid-merit load factors. However, the technical feasibility, especially relating to plant flexibility, of high capture rates needs to be further studied in greater detail through engineering analysis and practical demonstrations before confidence in this option be established.

Policy recommendations to incentivise CCS

Realising the potential of CCS technologies requires urgent policy incentives to solve the two main barriers to deployment: high capital expenditure and lack of revenue generation. Economic constraints are at the forefront of CCS related risks and challenges. Projects usually involve very high upfront capital investment (Capex), while lacking mechanisms to recover operational expenses (Opex), since captured CO_2 is not highly valued. Our techno-economic model already assumes a carbon price to represent future incentives, but governments may choose to employ a wide variety of policy mechanisms to create more investable business models for CCS. Table 1 lists some of the major emerging global support mechanisms or actions that can address this market failure stemming from high Capex and Opex.

[7] Ready for CCS retrofit: the potential for equipping China's existing coal fleet with carbon capture and storage. IEA, 2016.
[8] Towards zero emissions CCS in power plants using higher capture rates or biomass. IEAGHG, 2019.

Table 1: General policy solutions to Capex and Opex barriers of CCS projects

High CAPEX	Lack of OPEX Recovery
1. Capex-based tax credits to alleviate tax liabilities and ease project finance 2. Direct public procurement 3. Capital support through government grants, tax-exempt financing, concessional loans, accelerated depreciation or direct equity investment 4. Cheaper finance through progressive financing, international financing institutions or export credit agencies	1. Operational tax credits to increase profitability 2. CCS obligations with tradeable certificates: each retailer must source a minimum portion of their electricity from CCS power 3. Emissions Performance Standards with tradable CCS certificates: each retailer must source a minimum portion of their electricity from low carbon power 4. Feed-in-Tariffs (FiTs): plants are paid a fixed amount per unit of electricity produced or CO_2 captured 5. Contract for Difference (CfD): plants are guaranteed a fix amount of revenue per kWh or tonne CO_2 stored through topping up spot market prices 6. Topping up revenues via CO_2 utilisation, i.e. enhanced oil recovery (EOR), carbonated beverages, buildings, plastics, fuels, etc.

In addition to power generation companies, incentives must be developed for CO_2 transportation and storage (T&S) business models. Most CCS projects in the future are likely to use shared T&S infrastructure which will be managed by dedicated companies. Costs of T&S deployment can significantly be reduced through clustering capture facilities, oversizing initial assets and utilising existing assets which would otherwise be decommissioned. Furthermore, countries can accelerate T&S infrastructure roll-out via public ownership or regulated models which are currently applied to monopoly utilities in some regions.

Individual CCS applications have unique challenges which need to be addressed though targeted incentives and actions in order to enable their deployment at required rates. For example, the main barrier around flexible operation is the fact that currently discussed CCS incentives are designed to reward continuous running and maximised output. Challenges about hydrogen power stem from its dependence on a cross-sectoral shift to a hydrogen economy and several unproven technical capabilities about appliance and grid conversion. Similarly, limitations to BECCS include general lack of regulation and standardisation around negative emissions, as well as concerns about increased land use for feedstock production. Lastly, individual retrofitting plants suffer from efficiency losses and plant down-time during conversion. Table 2 below summarises some of the common policies and regulations that can overcome these technology specific issues.

Each country can assess the globally available policy options to determine the best actions suitable for their power market and unique circumstances. Table 2 includes a non-exhaustive list of recommendations to encourage CCS deployment for each of the 4 countries studied. Countries may want to expand on existing policy mechanisms that are proven to work well, such as Contract for Differences in the UK, tax incentives in the USA, premium wholesale electricity tariffs in China and the Renewable Energy Target in Australia. Furthermore, countries are advised to develop a CCS regulatory regime (China) or improve upon the existing frameworks (the UK, the USA and Australia) focusing on capping CO_2 storage liabilities. Another important area of urgent focus is establishing long-term national decarbonisation targets and developing technology roadmaps for CCS and hydrogen.

Table 2: Policies and recommendations to incentivise specific CCS technologies and suggested actions for individual countries, in addition to the general solutions in Table 1.

Category	Recommendations / Next Steps
Flexible Operation	• Establish capacity markets or include CCS plants in existing markets. • Develop novel policy mechanisms, such as flexible Contract for Difference, to incentivise CCS plants to flexibly run after intermittent renewables and before unabated fossil plants.
Hydrogen	• Ensure that technical challenges regarding 100% hydrogen turbines are resolved. • Define appropriate business models for the sustainable hydrogen supply-chain including power generation, taking into consideration carbon footprint accounting and avoiding double counting. • Support/incentivise low-carbon hydrogen production, which would indirectly support hydrogen for power. Grid blending, petrochemicals and power can be predictable early large-scale users for hydrogen deployment.
BECCS	• Developing detailed measurement, monitoring and verification standards for negative emissions. • Recognise and incorporate negative emissions in carbon pricing/accounting systems. • Implement stringent biomass sustainability criteria and help establish sustainable supply-chains. • Promote use of bioenergy with CCS to maximise negative emissions.
Retrofit	• Implement robust "CCS readiness" requirements of all new fossil plants, considering full chain as well as clustering options. Expand requirements to hydrogen and biomass/BECCS readiness. • Establish unabated fossil fuel to CCS transition plans, starting with coal, to incentivise retrofits. • When considering retrofit potential of plants, use a case-by-case approach rather than having very rigid project thresholding criteria.
UK	• Encourage future power plants to be in CCS cluster locations. • Expand the current Contract for Difference (CfD) scheme to include CCS and BECCS. • Consider a regulated asset base (RAB) model to deploy CO_2 T&S infrastructure. • Cap post-closure storage liabilities and let storage companies share risks with the government. • Implement further market-based incentives from Table 1 for CCS power companies and a regulated model to deploy T&S infrastructure.
USA	• Harmonise pore space ownership rights in neighbouring states. • Gaps in the incomplete federal CCS regulatory framework needs improving. • Cap storage liabilities, especially California Low Carbon Fuel Standard project requirements. • Resolve technical issues preventing coal CCS projects from qualifying for 48A tax credits. • Amend details of 45Q tax credits to encourage more dedicated storage projects than EOR. • Implement further market-based incentives from Table 1 for CCS power companies and a regulated model to deploy T&S infrastructure.
China	• Further develop CO_2 storage resources with state sponsored appraisal projects. • Establish a CCS legal and regulatory framework to guide future projects. • Expand premium national wholesale electricity tariffs of renewables to CCS. • Commit to allocating increased generation hours to initial CCS plants. • Adopt a state-owned/public procurement model for new CCS plants and T&S infrastructure.
Australia	• Announce a long-term emissions reduction target and publish a roadmap to achieve it. • Allow Clean Energy Finance Corporation to invest in CCS. • Establish a scheme such as the Renewable Energy Target for CCS and include BECCS in the Emissions Reduction Fund. • Further emphasise coal gasification and hydrogen power in the national hydrogen roadmap. • Implement further market-based incentives from Table 1 for CCS power companies and a regulated model to deploy T&S infrastructure.

Recommendations for further work

This study demonstrates the viability of a set of power CCS technologies to cost-effectively decarbonise baseload, mid-merit and peaking generation roles in distinct power markets. Realising this potential, however, would require urgent addressing of general, technology-specific and country-specific CCS challenges, with policy and regulatory actions that are explored in this report.

To further assess the role and value of power CCS projects, the following future work is recommended:

- A site-specific analysis of **conversion from coal to biomass co-firing, 100% biomass and BECCS** in the context of coal dependent markets
- A detailed BECCS study investigating the **impacts of biomass supply-chain, costs and life cycle emissions** on future bioenergy potential in each region
- A detailed hydrogen study investigating the **interaction of hydrogen for power with other industries** and the different sources of hydrogen production
- Expansion of the study into **other regions with unique power markets** and geographies such as India, South America, Middle East, Japan and Africa as well as development of a Europe-wide CCS case study focussing on asset sharing and interconnections.
- **Business model analysis and policy design** dedicated to flexible operation, hydrogen power generation and negative emissions
- Identifying best actions to **improve public acceptance of CCS** considering the unique roles it plays in various regions.
- **Wider CO_2 utilization pathways and coupling of power CCS with other sectors** should be explored through life cycle analysis studies. CO_2 utilization can provide additional economic benefits (e.g. selling CO_2 to greenhouses and beverage companies), decarbonise hard-to-abate sectors (e.g. synthetic fuels for aviation) and provide grid services such as energy storage.
- Tracking the development of **emerging power CCS technologies**, such as pressurized oxyfuel combustion, chemical looping combustion, supercritical CO_2 power cycles (including the Allam Cycle) to determine their potential impact on future power systems.

Contents

Acronyms

ATR	Autothermal Reforming
BECCS	Bioenergy with carbon capture and storage
BEIS	Department for Business, Energy & Industrial Strategy
Capex	Capital expenditure
CCC	Committee on Climate Change
CCGT	Combined Cycle Gas Turbines
CC(U)S	Carbon capture (utilisation) and storage
CfD	Contract for difference
CO_2	Carbon dioxide
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DG	Distributed generation
DICE	Direct injection carbon engine
DOE	Department of Energy
EOR	Enhanced oil recovery
EPS	Emissions performance standards
ETS	Emissions trading system
EU	European Union
FID	Final investment decision
FiT	Feed-in-tariff
FOAK	First of a kind
GCCSI	Global CCS Institute
GHG	Greenhouse gas
GW	Gigawatt
H2GT	Hydrogen gas turbine
IEA	International Energy Agency
IPCC	Intergovernmental Panel on Climate Change
LCA	Life cycle analysis
LCFS	Low Carbon Fuel Standard
LCOE	Levelised cost of electricity
LF	Load factor
kWh	kilowatt hour
MMV	Measurement, monitoring and verification
Mt	Million tonnes
MWh	Megawatt hour
NOAK	N-th of a kind
NVP	Net present value
OGCI	Oil and Gas Climate Initiative
Opex	Operational expenditure
R&D	Research and development
RAB	Regulated asset base
SDG	Sustainable Development Goal
SDS	Sustainable Development Scenario
SMR	Steam methane reforming
SOE	State-owned enterprise
SRMC	Short-run marginal cost
T&S	Transport and storage
WEO	World Energy Outlook

1. Introduction

1.1 Background

Many global studies, such as the IPCC's 1.5°C special report[9] and the International Energy Agency's (IEA) sustainable development scenario (SDS)[10] have shown that the deployment of Carbon Capture and Storage (CCS) is essential for meeting climate targets. For instance, exclusion of CCS from the scenarios increase the cost of reaching below 2°C targets the most, compared to exclusion of any other technology[11].

One reason for the high impact of CCS is its ability to decarbonise many sectors ranging from power generation to energy intensive industry (where CCS may be the only option for some facilities) and transportation (if used for hydrogen or biofuels production). Furthermore, CCS can provide negative emissions if it is combined with bioenergy (called bioenergy with CCS - BECCS) or used in direct air capture.

Negative emissions are very valuable for mitigating hard to abate greenhouse gas (GHG) emissions and for reducing CO_2 concentrations back to an acceptable range in case of overshoot. 88 out of 90 IPCC scenarios with at least 50% chance of limiting temperature rise to 1.5°C and the IEA's SDS use some level of negative emissions. According to the IEA[12], eliminating negative emissions requirements would only be possible with severe and costly social change going far beyond the energy sector.

CCS is particularly vital in the power sector as the SDS projects 84% of global power generation to be from low-carbon sources by 2040 compared to only 36% today. The scenario expects that globally 41% of coal and 16% of gas power generation will use CCS technologies. Moreover, many countries, such as China and India, have young and expanding fossil fuel fleets, which would be stranded if fossil fuel power plants were to retire prematurely. Therefore, CCS retrofits can allow utilisation of existing assets and help power generators to continue to recover their investments in a sustainable manner.

The role of various power CCS technologies are expected to be different across regions and timescales. For instance, coal CCS is likely to play a large role in developing countries for a long time, due to increasing power demand and availability of cheap domestic supplies. On the other hand, more developed regions, such as Europe are expected to phase-out coal plants and transition to natural gas. CCS plants are likely to operate as baseload generators in the short-term to rapidly recover their investment and then transition to a more flexible operation mode in the long-term to compliment high shares of intermittent renewables on the grid.

Currently 32 $MtCO_2$/year is captured by large-scale CCS facilities[10], 2.5 $MtCO_2$/year of which is through the only two power CCS facilities, Boundary Dam (Canada) and Petra Nova (USA), which have a combined generation capacity of 355 MW. Today's level of investment is in sharp contrast with the 16 GW/year power CCS build rate required between 2020-2040 and the ~2700 $MtCO_2$/year capture rate required of all CCS by 2050 in the SDS[10]. Although CCS is essential in these models, the current development rates are stalled far behind and urgent action is needed to meet the requirements.

A recent Element Energy report[13] for the Oil and Gas Climate Initiative (OGCI) identified the main reasons why CCS deployment lags behind required levels:

[9] Chapter 2: Mitigation Pathways Compatible with 1.5°C in the Context of Sustainable Development. Part of a wider report by the IPCC, 2018.
[10] World Energy Outlook, IEA, 2019.
[11] Climate Change 2014: Synthesis Report, IPCC 5th Assessment Report, 2014.
[12] https://www.iea.org/weo/weomodel/sds/
[13] Policy mechanisms to support the large-scale deployment of Carbon Capture and Storage, Element Energy and Vivid Economics, 2018.

- **Current policies are insufficient** for CCS to be deployed at a meaningful level, while the public sector withholds policy support until it sees how cost effective CCS will be and the private sector does not invest in initial projects until there is committed market support.
- **Current debates focus on costs of CCS** rather than their added value. Unlike renewables or nuclear, CCS does not generate electricity. Its real value stems from achieving deep de-carbonization through carbon abatement, which is not fully appreciated by all parties.
- **Lack of a unified voice** and narrative from CCS stakeholders prevents effective communication of its value proposition to the public.
- **A residual amount of uncaptured CO_2** prevents traditional CCS projects from reaching net-zero emissions and makes them seemingly incompatible with the most stringent climate targets, even though there are multiple ways to make CCS a net-zero emission technology.

1.2 Objectives and scope

In light of the above discussion, it is clear that a collection of various CCS technologies (coal/gas post-combustion, hydrogen, BECCS, etc.) operating at different roles (baseload, flexible generation) across long timescales are needed to be deployed at high rates in different geographies around the world, despite many challenges preventing mass adoption.

The objective of this study is to explore the key roles and business cases for CCS in the evolving power sector considering:

- The regional power market drivers and outlooks in key countries;
- The ability of CCS to play a baseload and/or flexible role, including the ability of CCS power plants to adapt (shifting from baseload to more flexible role) as the electricity system evolves;
- The reasons why CCS has not progressed as expected a decade ago; and
- Measures that may be taken to progress CCS at a rate more consistent with current projections going forward.

1.3 Methodology overview and report structure

The project methodology, as outlined in Figure 2, consists of six main steps:

- Analysis of recent power sector evolution in each region to identify key drivers.
- Review of power sector outlooks to understand the expected future roles of CCS technologies.
- Techno-economic analysis to determine competitiveness of different CCS technologies.
- Review of past CCS projects to understand factors underlying success or failure.
- Identification of CCS deployment challenges and policy recommendations to unlock investment.
- Collating stakeholder feedback and findings from previous steps to create regional power CCS narratives including actionable next steps.

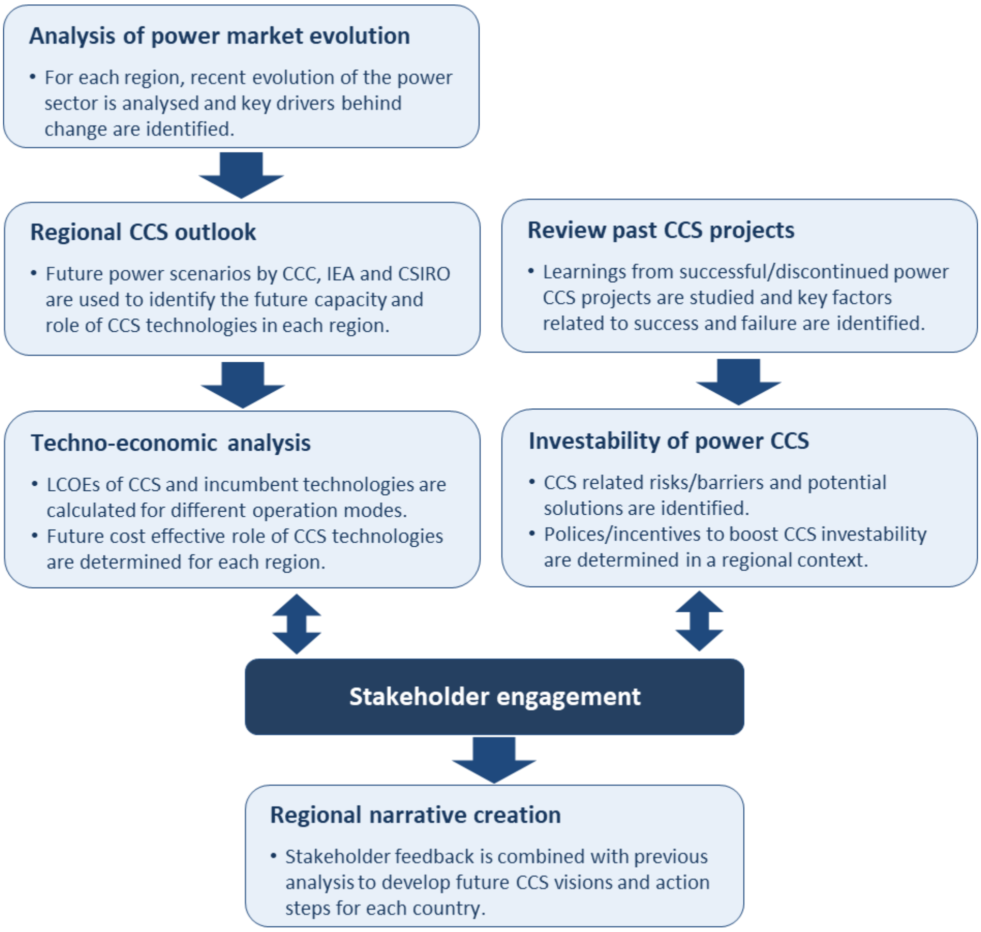


Figure 2: Key aspects of project methodology

The rest of this report is structured into 5 sections as follows:

Section 2 focuses on each country separately and reviews the drivers behind their power market evolution and the role of CCS in future power sector outlooks. Later, a techno-economic analysis is included to compare economic viability of CCS technologies in different operational modes.

Section 3 summarises key learnings from past CCS projects and presents policy recommendations to incentivise investment in different CCS technologies. Later, current CCS support of each country is reviewed, and specific actions/improvements are identified for each region.

Section 4 summarises the key conclusions and recommendations for further work while section 5 lists the references. Lastly, section 6 contains the appendix showing detailed assumptions, results and data acquired for this project.

2. Regional power market evolution and future role of CCS technologies

2.1 Scope and structure of this section

This study focuses on four regions to understand the different roles CCS technologies are likely to play in different power markets, each represented by a single country: Europe (UK), North America (USA), Asia (People's Republic of China or "China") and Australia. Although results are specific for each country, they represent high-level archetypes for other countries with similar power markets and drivers.

The UK, USA, China and Australia are chosen as representative countries because of a combination of factors such as their high carbon footprint, large economy and involvement to date with CCS technologies. The UK is also a comparable representation of Europe because it has a similar power generation composition to the European Union (EU), except for a higher level of natural gas power generation and a lower level of coal generation[14]. Also, the UK has high offshore CO_2 storage potential, which may be shared in the future by neighbouring European countries.

The four selected countries also represent a variety of different market conditions: USA has abundant low-cost shale gas, China has a rapidly growing electricity demand and domestic coal production, Australia depends very heavily on fossil fuels as a coal and gas exporter, and the UK plans to completely phase-out coal power in favour of natural gas and has high renewables penetration.

The rest of section 2 is structured in a region-specific way. First, an analysis of the recent power market evolution for each country is provided, which examines the change in their installed capacity and power generation sources over the last 15 years. Then, key drivers for the electricity sector in each country - such as domestic fossil fuel resources, energy security and renewables policies - are provided.

A following sub-section investigates the role of CCS in future power outlooks in each country. The main reference for this section is the IEA's World Energy Outlook (WEO) and specifically the Sustainable Development Scenario (SDS), explained further below. SDS figures are used for projections in the USA and China. However, since the WEO does not provide detailed information on the UK and Australia, other sources are used for these regions.

World Energy Outlook - SDS

The SDS aims to deliver on 3 energy-related UN Sustainable Development Goals (SDGs): to achieve universal energy access, to reduce severe health impacts of air pollution and to combat climate change. The scenario starts from the desired outputs and works backwords to determine what technologies, policies and investments are needed in each region to reach targets. SDS delivers global net-zero emissions by 2070 and has a 66% chance of limiting global temperature rise to below 1.8°C and a 50% chance of limiting it below 1.65°C.

Figure 3 below (left) shows the global power generation projection in the SDS. Renewables are expected to be the technology of choice and increase their share of generation from 26% in 2018 to 67% in 2040. Nuclear is projected to expand steadily and coal to rapidly be removed from the system. Natural gas generation is forecasted to grow in the medium term and eventually start declining. The net change in the installed capacity, Figure 3 right, broadly agrees with these findings. The reduction in fossil generation, combined with increased gas capacity, results in gas and coal plants frequently running as peaking plants at low load factors.

[14] "The EU got less electricity from coal than renewables in 2017". Simon Evans, Carbon Brief, 30.01.2018 https://www.carbonbrief.org/eu-got-less-electricity-from-coal-than-renewables-2017

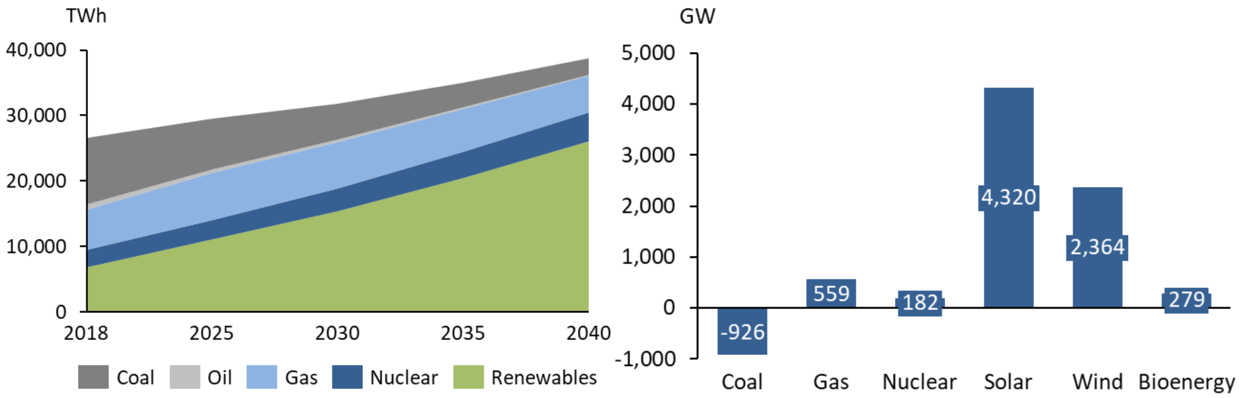


Figure 3: Global electricity generation outlook (left) and net installed capacity change (right) from 2018 to 2040 in the SDS

Table 3 below summarises power CCS projections in the SDS in 2040, broken down by fuel type and retrofit/new build plants. Both gas and coal CCS plants are expected to operate at relatively high load factors as baseload generators, while unabated plants are projected to have significantly lower load factors, indicating their role as peaking generators, providing system flexibility. 88% of coal and 44% of gas CCS capacity are retrofits and the global split between coal and gas is fairly even with 994 TWh and 915 TWh, respectively.

Table 3: 2040 global power generation, capacity and load factors of CCS technologies in SDS

Fuel	Type	Generation	Capacity	Load Factor[15]
Coal	Unabated	1434 TWh	988 GW	17%
	Retrofit CCS	994 TWh	145 GW	69%
	New CCS		20 GW	
Gas	Unabated	4669 TWh	2149 GW	25%
	Retrofit CCS	915 TWh	68 GW	67%
	New CCS		87 GW	

Techno-economic analysis

Lastly, each sub-section concludes with a regional techno-economic analysis indicating different roles (baseload, mid-merit, peaking) CCS technologies may play in each country. The analysis involves comparing levelised cost of electricity (LCOE) of counterfactual technologies with CCS options (refer to appendix 1 for more detail). The CCS technologies analysed in this study are:

- Amine-based post-combustion capture (90%) from supercritical coal power plants.
- Amine-based post-combustion capture (90%) from combined cycle gas turbines (CCGTs).
- BECCS with amine-based post-combustion capture (90%) from a subcritical circulating fluidised bed reactor burning domestic wood-based feedstock.
- Power generation through hydrogen gas turbines (H2GTs), where hydrogen is produced via pre-combustion capture. Specifically, hydrogen is produced via coal gasification in China, autothermal

[15] Load factors are provided for the combined new and retrofit CCS fleet.

reforming (ATR) using natural gas in the UK[16,17] and steam methane reforming (SMR) in the USA and Australia.

- Various retrofit opportunities are also investigated as case studies.

The LCOEs are compared for first-of-a-kind (FOAK) plants commissioning in 2025 and Nth-of-a-kind (NOAK) plants commissioning in 2035. In general, NOAK plants are expected to be cheaper than FOAK plants due to learning rates and technology improvements. CCGTs and coal plants do not benefit from learning rates as they are already mature technologies.

Throughout this report, unless stated otherwise, a 10% discount rate and a 25-year financial lifetime[18] are assumed for all technologies, except for nuclear and battery storage, which have a 60-year and 10-year lifetime respectively. The captured CO_2 is assumed to be stored permanently. Transportation and storage (T&S) infrastructure is not modelled site specifically and a fixed T&S fee per tonne of CO_2 is assumed. Similarly, a flat hydrogen price per MWh is used for the specific production technology and region.

Two different types of BECCS LCOEs are included in this study. The first, labelled "BECCS" on graphs, represents only including scope 1 emissions from the plant. In other words, it assumes that all the captured CO_2 (90% of the embedded carbon in feedstock) is eligible for negative emissions credits, which is assumed to have the same value as the regional carbon price. A second calculation is made, labelled "BECCS LCA Emissions" on graphs, accounts for all the life cycle analysis (LCA) emissions, which may be as much as 50% of the embedded carbon[19]. Hence, this bar represents claiming only 50% of the carbon content in the biomass as truly negative emissions. Currently there are no large scale BECCS facilities in the world and carbon accounting methodologies for negative emissions are not fully developed. Moreover, the amount of negative emissions recognized for policy purposes may be different than the actual negative emissions delivered. Therefore, these 2 calculations aim to represent the maximum and minimum carbon savings scenarios, where the actual LCOE of BECCS may be anywhere between these 2 estimations.

2.2 United Kingdom

2.2.1 Key drivers of recent power market evolution

Since the 1990s several factors, such as the availability of cheap domestic natural gas in the North Sea and the privatization of the power sector, led to the "Dash for Gas" in the UK[20]. Coal generation was steadily replaced by gas and CCGTs, which helped to partially reduce electricity-related emissions. From the mid-2000s, the UK's gas imports started increasing[21] as domestic production declined, making the country a net gas importer.

In 2008, the Climate Change Act enshrined in law a national target to reduce GHG emissions by 80% by 2050 compared to 1990 levels and drove support for renewable energy. Since 2008, the power sector, and particularly renewables, was responsible for the majority of the UK's emissions reductions[22]. The law was amended in 2019, after the Committee on Climate Change's (CCC) Net Zero report[23] was published, to a target of 100% emissions reduction by 2050.

[16] H21 North of England, by Northern Gas Networks, Equinor and Cadent, 2018.
[17] Hydrogen for power generation: opportunities for hydrogen and CCS in the UK power mix, Element Energy study for Equinor, 2019.
[18] Although operational lifetime of plants are likely to be higher than 25 years, financial return is typically expected relatively early. Furthermore, plants may require major retrofits to continue operations, hence a 25-year period is used here.
[19] BECCS deployment: a reality check. Fajardy, M., et al. Imperial College London, 2019.
[20] UK's Dash for Gas: Implications for the role of natural gas in European power generation. Alexandra-Maria Bocse & Carola Gegenbauer, 2017.
[21] IEA online energy statistics, https://www.iea.org/statistics/
[22] Reducing UK emissions – 2018 Progress Report to Parliament, CCC, 2018.
[23] Net Zero: The UK's contribution to stopping global warming, CCC, 2019.

Figure 4 shows the change in installed capacities and power generation source[21] in the UK since 2005. The share of renewables has increased steadily as the overall electricity demand stalled and even decreased slightly due to efficiency improvements and economic and environmental challenges. Nuclear generation provided baseload power and its share mostly stayed constant as well.

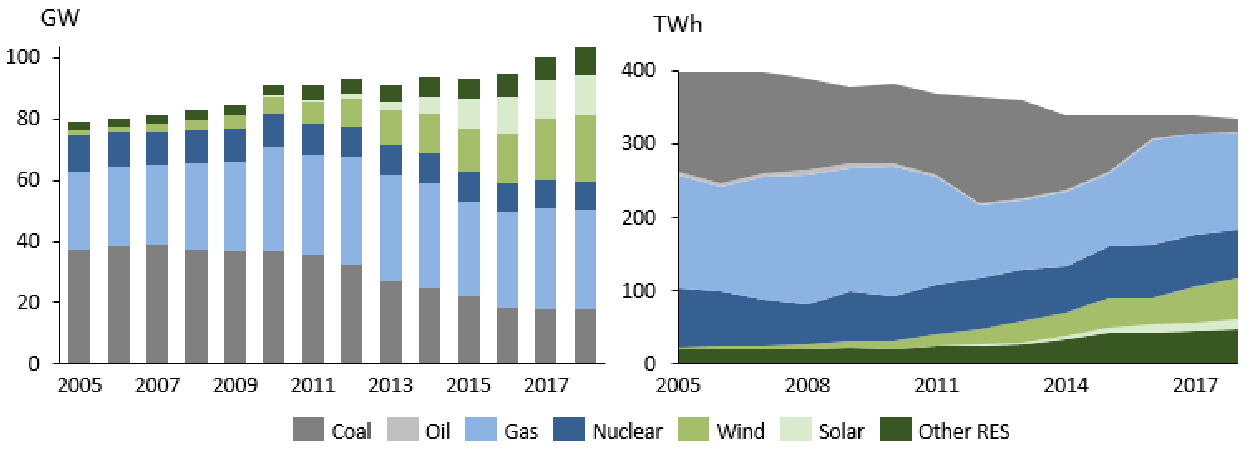


Figure 4: UK breakdown of installed power capacity (left)[24] and generation source (right)[21]

The change in the electricity sector was driven by several different policies. The initial small-scale wind and solar PV capacities were incentivised through Feed-in-tariffs (FiT), which have been discontinued since 2019. In 2013, Electricity Market Reform[25] introduced Contract for Differences (CfDs) as the main instrument to support investment into low carbon technologies. Under this scheme, projects would enter an auction to secure a strike price and the government would pay them the difference between the strike price the wholesale electricity price at the time of generation. This would create predictable and secure revenues for otherwise risky projects. The Electricity Market Reform also established the Carbon Price Floor, which topped up the carbon price of the EU Emissions Trading System (EU ETS) to a minimum level, further driving a shift away from coal.

The UK currently has 5 GW of interconnectors to France, the Netherlands, Belgium, the Republic of Ireland and Northern Ireland, providing system security and flexibility. One of the future aims of the UK power system is to successfully integrate increasing shares of intermittent renewables.

2.2.2 CCS in the power sector outlook

Before the national net-zero target was adopted in 2019, CCC released a report[26] looking at technically and economically feasible pathways to achieve this target. They identified actions that would allow the country to meet its previous 80% reduction target, as well as further ambition scenarios which would be necessary to reach net-zero. Figure 5 below shows a representative power generation mix for CCC's 2050 further ambition scenario.

Despite improved energy efficiency, UK electricity demand may double by 2050 due to partial electrification of transport, industry and heating. This demand is expected to be met by a range of different technologies, renewables (especially offshore wind), being the largest contributor at 59%. A combination of existing and new nuclear is also projected to contribute at ~12%.

[24] Digest of UK energy statistics (DUKES): electricity. BEIS, 2019.
[25] UK electricity market reform and the Energy transition: emerging lessons. Michael Grubb and David Newbery, 2018.

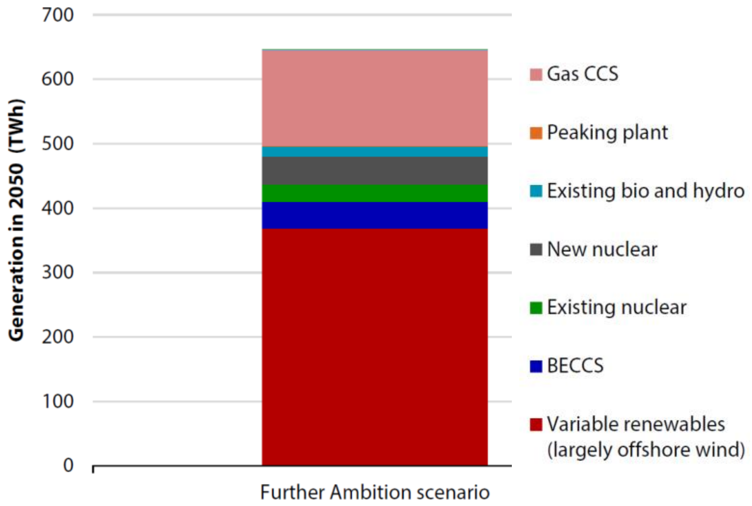


Figure 5: A representative UK 2050 power generation mix under the Further Ambition scenario of CCC's Net-zero report[26]

Table 4 below summarises the capacities and roles of various CCS technologies in the further ambition scenario. As the UK is on a path to completely phase out coal by 2025, no coal CCS plants are included in the scenario. On the other hand, a combination of firm (baseload) and flexible gas CCS plants are expected to deliver 23% of total power demand. The report identifies the importance of building 1-2 GW of new mid-merit gas CCS per year between 2030-2050, which equates to a total of 20-40 GW by 2050, operating at load factors in the range of 20-25%. This projection further implies a fleet of 2-10 GW firm gas CCS plants expected to run at high load factors.

Moreover, the CCC predicts that a small capacity of BECCS (5 GW) would produce negative emissions, operating at a 94% load factor. It is emphasised that since sustainable feedstock supplies are restricted the most impactful way of utilising bioenergy would be maximizing its negative emissions potential by directing biomass to BECCS plants running at baseload. These plants would offset residual emissions from gas CCS facilities and other hard to de-carbonise industries to reach net-zero.

Table 4: 2050 UK power generation, installed capacities and load factors of CCS technologies in the CCC's Further Ambition scenario[26]

Fuel	Type	Generation	Capacity	Load Factor
Gas	Unabated	-	-	-
	New CCS Baseload	150 TWh	2-10 GW	75-90%
	New CCS Mid-merit		20-40 GW	20-25%
BECCS	New Built	41 TWh	5 GW	94%
Hydrogen	New Built	< 2 TWh	> 40 GW	< 0.6%

Lastly, the electricity system would need a large capacity of backup generators, which would operate as peaking plants and provide electricity at rare times when demand cannot be met by renewables and firm generation. The CCC expects that the peaking plants can be decarbonised through using hydrogen

[26] Net Zero Technical Report. CCC, 2019.

turbines, which would reduce costs compared to a CCS facility since they would not have to invest in on-site capture facilities. However, these H2GTs are expected to run at extremely low load factors (<1%) and new policies would have to be developed to incentivise investment into peaking plants, since existing market mechanisms do not reward plants idling for extended periods.

2.2.3 Future role of CCS technologies

Most of the capital expenditure (Capex), operational expenditure (Opex) costs and carbon prices[27] for the UK are based on data and guidance published by BEIS (Department for Business Energy and Industrial Strategy). Please refer to appendix 1 for more detail.

Baseload generation

Figure 6 below shows the LCOEs of technologies operating at a representative 90% load factor. Although coal CCS is cheaper than its unabated counterpart, coal plants are more expensive than gas options and are not expected to play a role in the UK. For FOAK plants commissioning in 2025, unabated CCGTs are the cheapest option, but CCGT CCS plants can still be justified as they are expected to be only slightly more expensive. The new generation of nuclear plants (European Pressurised Reactors) are expected to reduce their costs in the NOAK stage but are still estimated to be an expensive option compared to CCS technologies.

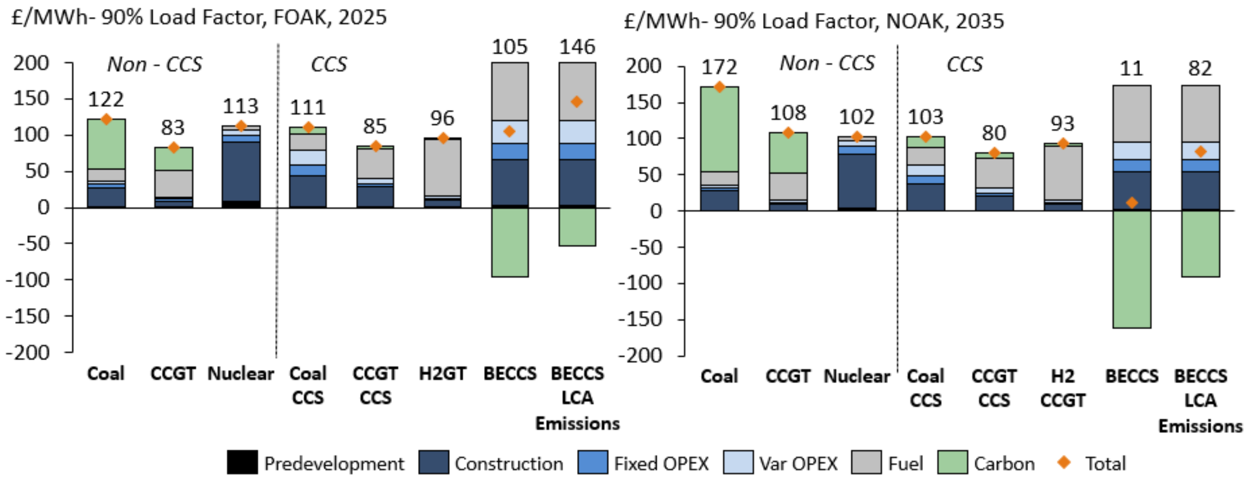


Figure 6: UK- future LCOE comparison of technologies operating as baseload generators

The NOAK calculations shown on the right-hand side are affected by increased carbon prices experienced through the lifetime of plants commissioning in 2035. All the CCS options outperform counterfactual technologies, however, coal and hydrogen are still not expected to have a baseload role in the UK. Gas CCS is expected to be clearly more cost-effective than its unabated counterpart. However, BECCS becomes the cheapest option by far with high negative emissions and stays competitive even if all the LCA emissions are accounted for. It may be possible to operate BECCS plants at extremely low costs (£11/MWh), although future biomass prices may increase substantially if BECCS becomes a widespread technology. Out of all the regions studied, BECCS has the lowest relative costs in the UK, due to high carbon price projections.

In short, the UK may cost-competitively start deploying CCGT CCS from mid-2020s and BECCS from 2030s to operate as baseload generators with high load factors.

[27] UK carbon price in the model: £44.3/tCO_2 in 2025; £110.7/tCO_2 in 2035; £287/tCO_2 in 2060.

Mid-merit generation

Figure 7 below shows the same LCOE analysis assuming a 45% load factor, which is representative of mid-merit operation. Nuclear plants are not included as they would not run flexibly. None of the CCS options are economically viable in 2025 because as plants operate at lower load factors, they are subject to lower carbon costs.

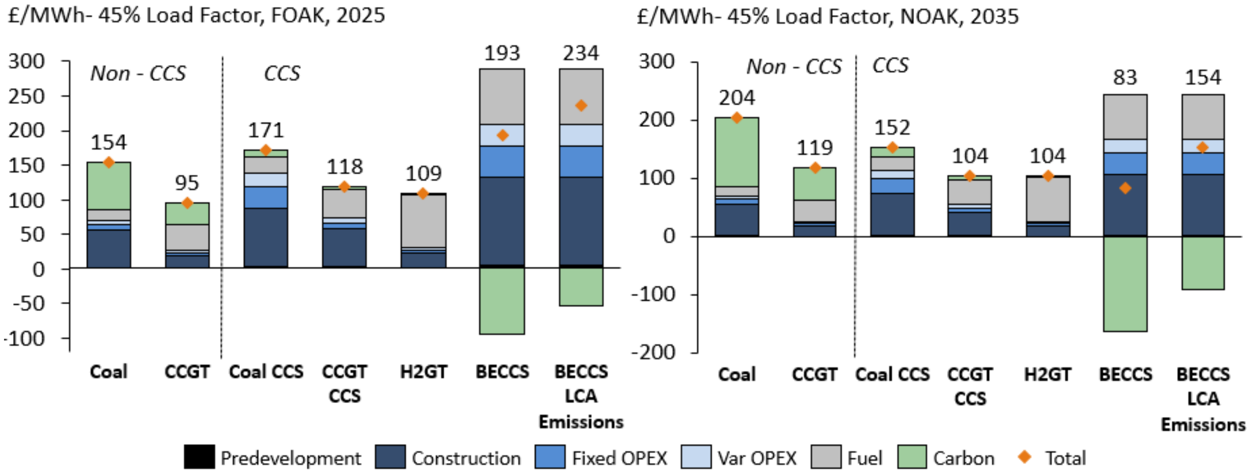


Figure 7: UK- future LCOE comparison of technologies operating as mid-merit generators

However, both CCGT CCS and H2GTs are expected to have very similar LCOEs and be competitive as NOAK technologies in 2030s. Furthermore, depending on the actual carbon accounting system, BECCS may be a viable option as well. Even if BECCS becomes cost effective under a high carbon price, it is not expected to have a role other than baseload, since its aim would be to maximise its negative emissions.

Peaking generation

The peaking power plant operations are modelled assuming a 15% load factor and results are shown in Figure 8 below. Coal is not included in the analysis because coal plants have much higher Capex than CCGTs, thus are not expected to be cost effective at low load factors. “BECCS LCA Emissions” are not included due to very high costs as well. On the other hand, battery storage with 4, 8 and 12-hour discharge times are added to the study, as they are expected to be a prominent flexibility technology in the future.

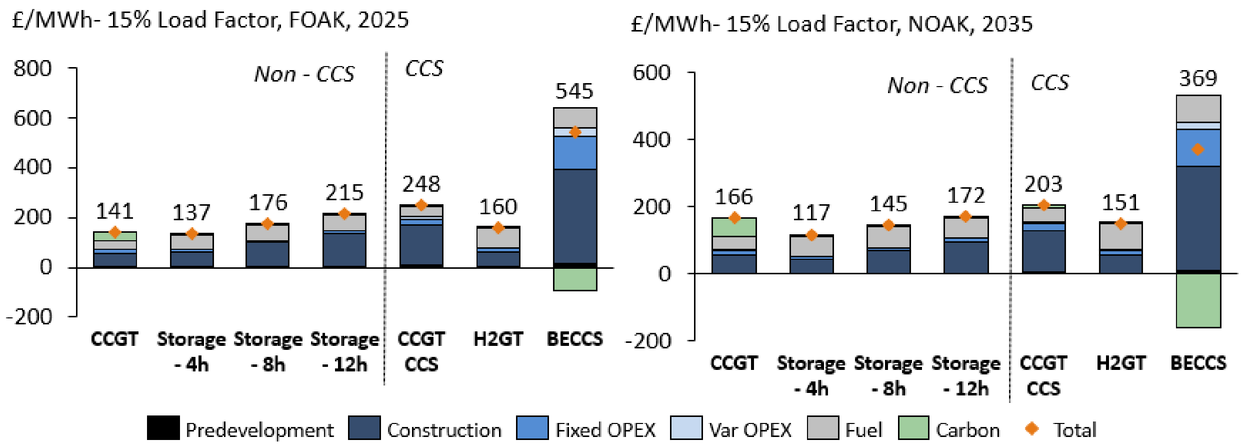


Figure 8: UK- future LCOE comparison of technologies operating as peaking generators

Costs of battery storage increase with discharge periods as significantly more Capex is needed to build larger batteries. In 2025 unabated CCGTs and 4-hour batteries are very cost competitive options. However, NOAK H2GTs in 2035 are cheaper than unabated CCGTs and can compete with battery storage options with more than 8 hours of discharge time. The competitiveness of H2GTs are attributable to their relatively low Capex, which becomes a large LCOE component at low load factors. Other CCS options are not viable for peaking generation for the same reason.

Retrofits

Box 1: Drax power plant – a case study for coal to BECCS retrofit

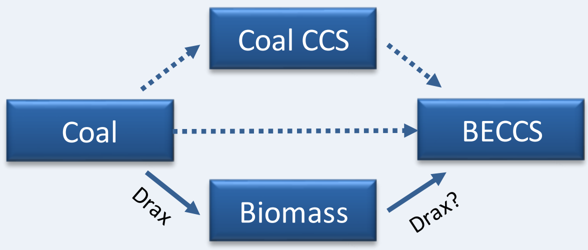
Drax is UK's largest power plant with a 3.9 GW capacity. It was first commissioned in 1975 in North Yorkshire (England) as a coal plant and currently supplies ~6% of the UK's electricity demand. The plant underwent several upgrades and expansions, latest of which involved converting 4 of its 6 turbines (each 660 MW) to run on 100% biomass. The conversion happened between 2013 and 2018 after several years of co-firing biomass with coal.

Currently Drax sources its biomass from sustainable forestry products overseas, mostly North America. There is also a pilot BECCS project on-site in partnership with C-Capture, a UK start-up developing novel carbon capture technologies. Depending on the results of the demonstration, Drax plans to become the first large-scale BECCS plant by retrofitting CCS to its biomass turbines.

Drax is also considering converting its 2 remaining coal turbines to flexible CCGTs in a 2023/24 timeframe. These conversions would extend the lifetime of the power plant and utilise existing assets to reduce costs. Drax further benefits from being in the Yorkshire & Humber area, a region which may become a CCS cluster and develop CO_2 T&S infrastructure due to the many large industrial facilities and power plants located there.

Although there are unique circumstances incentivising Drax's decision to convert from coal to BECCS, such as the UK government's plan to phase out coal by 2025, it may set an example for how coal dependent countries can slowly shift to more sustainable options. The schematic below summarises some of the potential routes for this conversion.

Other than full on retrofitting, it is possible to co-fire 10-15% (by energy) biomass with coal without significant Capex investment. If a coal plant is fitted with CCS, biomass co-firing may eliminate all residual emissions and even achieve negative emissions. Currently, there has been little investigation of this coal to BECCS route, and it may provide a cost-effective way of achieving negative emissions with little investment for countries which depend heavily on coal.



In order to investigate the viability of retrofitting CCS technologies a case study is conducted calculating the net present value (NPV) of retrofitting a CCS unit to a CCGT or converting a CCGT to an H2GT in 2030 and 2035. It is assumed that the remaining lifetime of plant is 20 years after the retrofit and CCGT plants will lose a part of their revenues to efficiency reduction after the CCS retrofit. Please see appendix 1 for more information on assumptions.

As shown in Figure 9 below, CCS retrofitting is economically viable for a mid-merit plant (45% load factor) but not for a peaking plant (15% load factor) irrespective of timing. Therefore, the choice of retrofitting would depend on projected load factors in the future and may be incentivised by guaranteeing a minimum load factor to the plant. The investment decision for H2GT retrofit is not affected by load factors but by the carbon price. In early 2030s, carbon price is expected to rise to sufficient levels that justify converting to hydrogen.

The analysis presented here is only illustrative of a simple set of assumptions. The retrofit case for each individual plant would look very different depending on its location, age, available incentives, etc. Also, if a retrofit decision is delayed too much, the remaining lifetime of the plant may not be enough to recover investment. On the other hand, if lifetime is extended through turbine replacement, retrofit economics may look more cost-effective than presented here. Lastly, it is possible to blend a small ratio of hydrogen in CCGTs and any ratio of bio-based gas in CCGTs and H2GTs without significant Capex investment. All these options would have to be carefully studied to better understand the role of retrofits in a future CCS outlook.

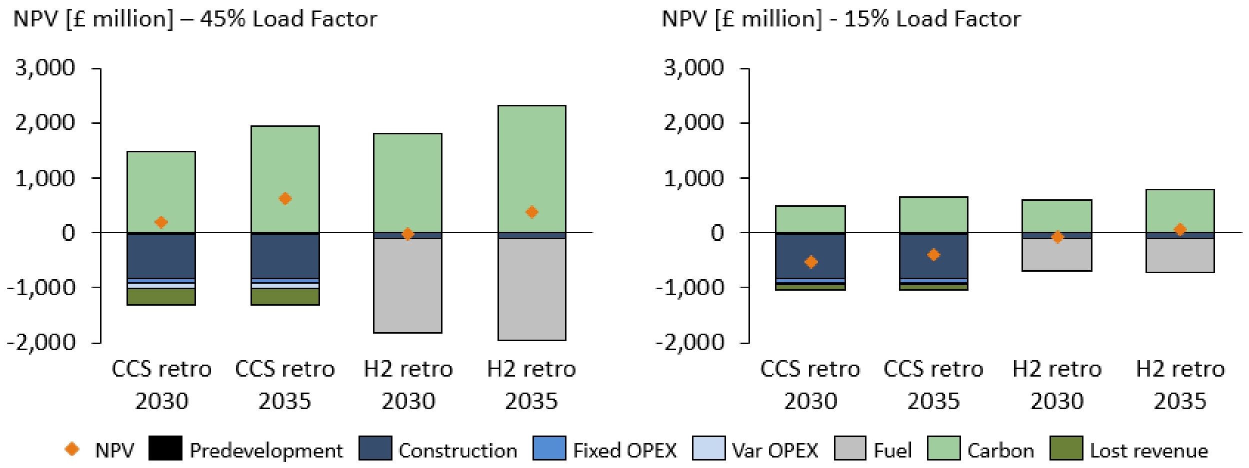


Figure 9: Net present values of retrofitting a CCGT plant with CCS or hydrogen at different load factors and timescales

2.3 United States

2.3.1 Key drivers of recent power market evolution

In the 21st century, the US power sector started transitioning away from coal to natural gas, which is supported by the "shale gas boom". Very low gas prices and lower relative emissions from gas are the key drivers for this transition. In 2016, power production from gas exceeded that from coal for the first time and in 2017 the USA became a net gas exporter, as seen in Figure 10 right[21].

Figure 10 left shows the power generation breakdown of USA since 2005[21]. Overall demand stagnated as renewables increased their share slightly and market-driven fuel switching from gas to coal generation reduced power sector emissions by 28% since 2005. Renewables constituted the majority of new capacity additions since 2014, except for 2018, where gas power plants were the highest instalments[28].

Whereas gas fuel switching is cost driven, investment in renewables are realised through several different policies. The USA has no federal renewable energy target but financial incentives such as production and investment tax credits have been instrumental in uptake of renewable energy. Furthermore, 29 states and District of Columbia have binding Renewable Portfolio Standards, requiring electricity suppliers to source a certain portion of their energy from eligible generators. California, for instance, set targets of 33%, 50% and 100% for 2020, 2030 and 2045, respectively.

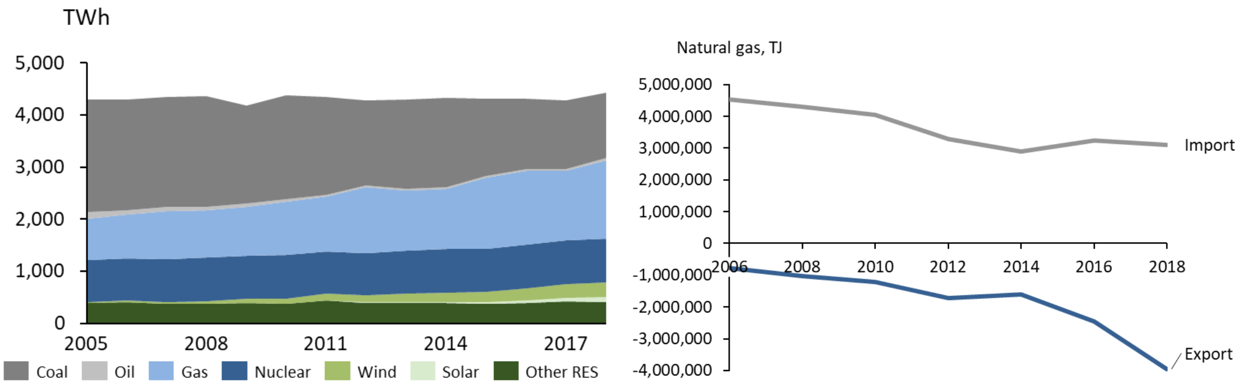


Figure 10: USA power generation breakdown (left)[21] and gas imports/exports (right)[21]

In 2018 45Q tax credits, a federal incentive which alleviates tax obligations of companies capturing and storing CO_2, was amended to increase credit awards to \$50/tCO_2 for storage in saline aquifers and \$35/tCO_2 for using the CO_2 in enhanced oil recovery (EOR). The maximum credit cap was removed, and credits became transferable between companies in the same CCS project chain. The enhanced 45Q tax credits, which is now considered to be one of the most direct flagship CCS incentives in the world, recently generated interest in new CCS and direct air capture projects.

2.3.2 CCS in the power sector outlook

WEO Sustainable Development Scenario (SDS) predicts a rapid uptake of renewables and phase-out of coal in the USA by 2040. As shown in Figure 11 a small net gas capacity addition is expected, as gas generation goes through expansion followed by decline. All unabated coal plants are projected to be shut down as significant wind and solar PV capacity is added to the system. Bioenergy generation is also expected to almost triple by 2040 to constitute 4.4% of the power mix.

Table 5 summarises implications for 2040 US power CCS capacities and generation in the SDS. Gas and coal CCS load factors for all countries are assumed to be equal to global averages. According to WEO 2019, the USA is expected to have 10 GW of coal CCS retrofits by 2040, which would produce all the national coal power, implying there would not be any unabated or new built CCS plants.

WEO 2019 does not specify national gas CCS projections, therefore WEO 2018 gas CCS generation data is used in conjunction with updated load factors from WEO 2019 to estimate the total capacity of gas CCS in the USA. Under these assumptions, USA is expected to have ~94 GW of gas CCUS by 2040 and generate 61% of all gas CCS power globally, driven by its large market and low-cost shale gas availability. If the USA follows similar trends to the global average, just under half of this gas CCS capacity may be retrofits. Lastly, a very large fleet of unabated gas plants are expected to operate flexibly, reducing their load factors from around 55% in 2018 to 15% in 2040. These plants would be necessary for integration of

28 Annual Energy Outlook 2019, U.S. Energy Information Administration, 2019.

high shares of variable renewable energy, but they will require new market mechanisms to be viable business models.

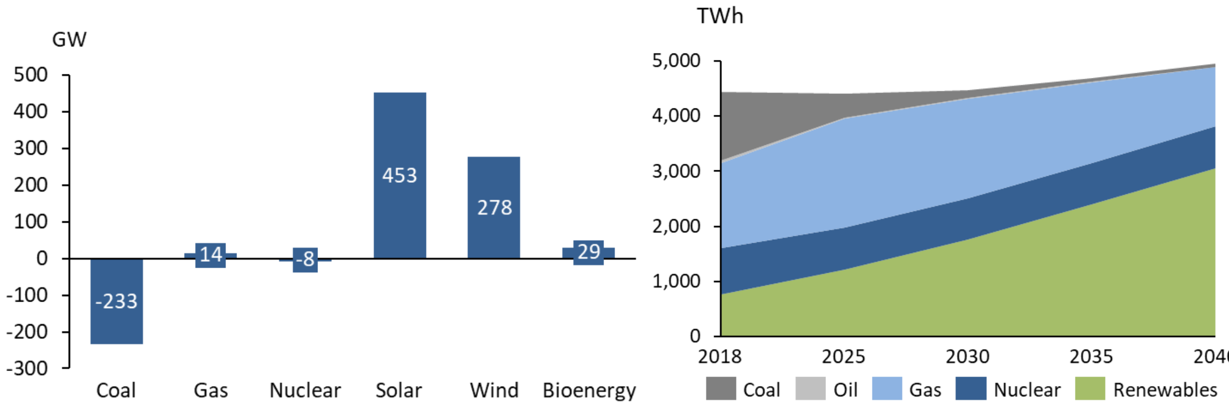


Figure 11: Net change in installed capacity (left) and power generation breakdown (right) for the USA between 2018-2040 in SDS

Table 5: USA 2040 projections of CCS capacities and load factors as interpreted from SDS[29]

Fuel	Type	Generation	Capacity	Load Factor[30]
Coal	Unabated	-	-	-
	Retrofit CCS	60 TWh	10 GW	69%
	New CCS	-	-	-
Gas	Unabated	521 TWh	410 GW	15%
	Total CCS	~556 TWh	~94 GW	67%

2.3.3 Future role of CCS technologies

Please refer to appendix 1 for more detail on Capex, Opex and carbon price[31] assumptions for the USA.

Baseload generation

Figure 12 below compares LCOE of FOAK and NOAK technologies operating as baseload in the USA. Coal CCS options are found to be cheaper than their unabated counterparts but are not economically viable compared to CCGT options due to low-cost local shale gas. On the other hand, CCGT CCS is expected to be the most cost-effective technology, even in mid-2020s. By mid-2030s BECCS has a chance of getting competitive with unabated CCGTs depending on the final carbon accounting mechanism chosen. WEO predicts more bioenergy to be used in the system and the most ideal way to utilise biomass would be to generate negative emissions, which may translate to further policy support for BECCS. Lastly, H2GTs are not expected to compete with CCGTs at high load factors. In short, baseload CCGT CCS and BECCS plants are expected to be commissioned in the USA starting from 2020s and 2030s, respectively.

[29] Gas generation and capacity data are calculated by using gas CCS generation data of WEO 2018 with CCS load factors of WEO 2019.
[30] Load factors are provided for the combined new and retrofit CCS fleet.
[31] Carbon price based on SDS (advanced economies): £46.4/tCO_2 (2025), £89.0/tCO_2 (2035).

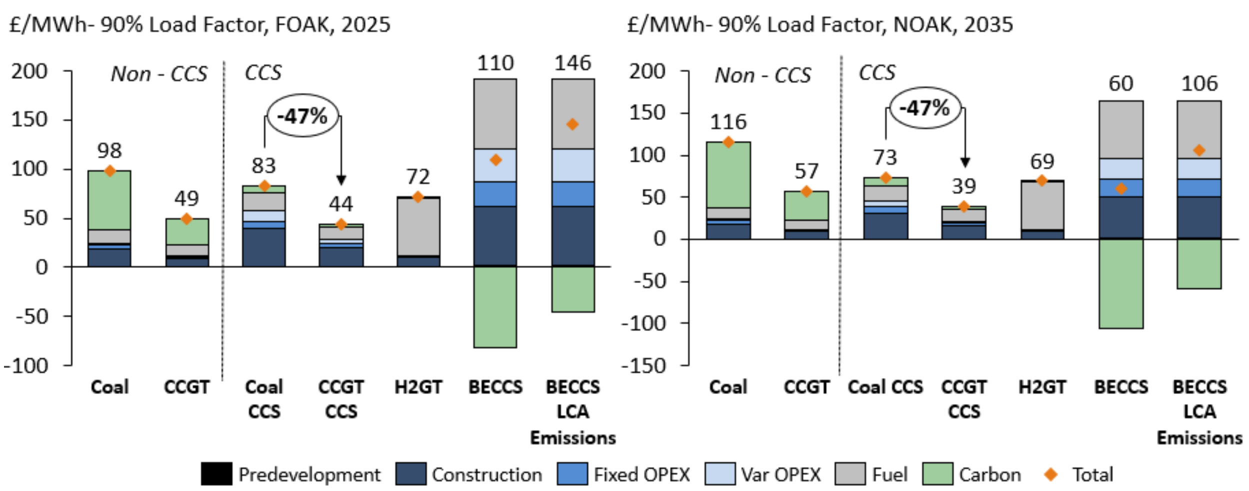


Figure 12: USA- future LCOE comparison of technologies operating as baseload generators

Mid-merit generation

Figure 13 left compares LCOEs of NOAK mid-merit technologies commissioning in 2035. "BECCS LCA Emissions" are not included because BECCS has very high costs compared to all other technologies shown. Also, as discussed previously, BECCS is not expected to have a role other than baseload. CCGT CCS plants are the lowest cost option starting from early 2030s, but not earlier under these assumptions. H2GTs are still the second best CCS option and are not likely to operate at medium load factors.

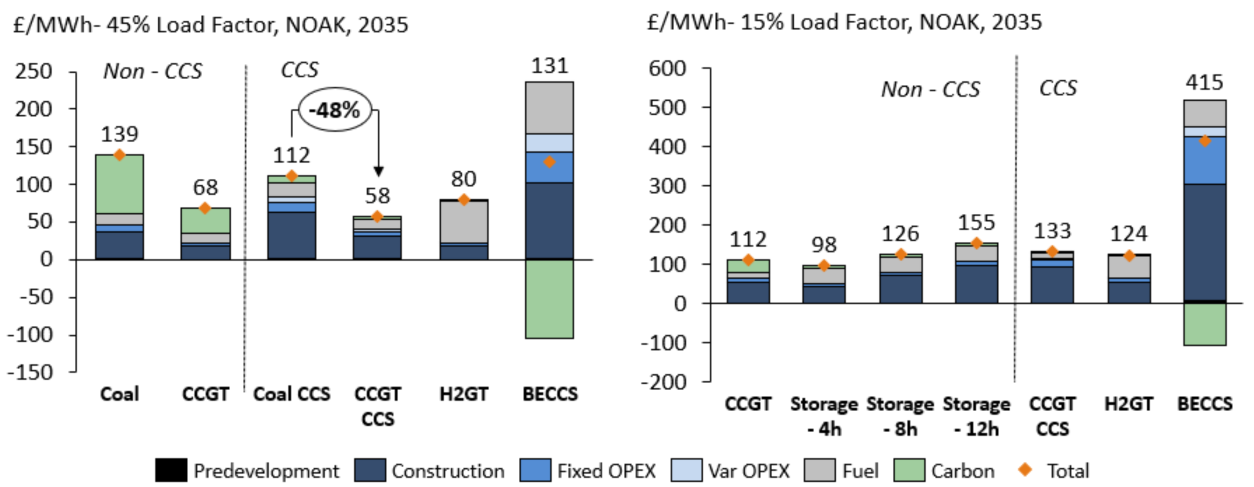


Figure 13: USA- 2035 LCOE comparison of NOAK technologies operating as mid-merit (left) and peaking (right) generators

Peaking generation

Figure 13 right repeats the same analysis on NOAK peaking plants with a 15% load factor. Coal plants are replaced by battery storage options as probable flexibility options. At lower load factors H2GTs are the cheapest CCS option, which is competitive with batteries with 8 or more hours of discharge time. Figure 14 presents a sensitivity analysis around change in LCOEs with respect to load factors. H2GTs become cost-effective compared to CCGT CCS and 8-hour battery storage at load factors lower than 18% and 17% respectively. However, except for 4-hour battery storage, unabated CCGTs are the next cheapest technology for load factors lower than 26%. Therefore, decarbonising the niche market of peak generation for extended periods (>8 hours) would require the government to incentivise H2GTs to a greater extent than the carbon price used in this study.

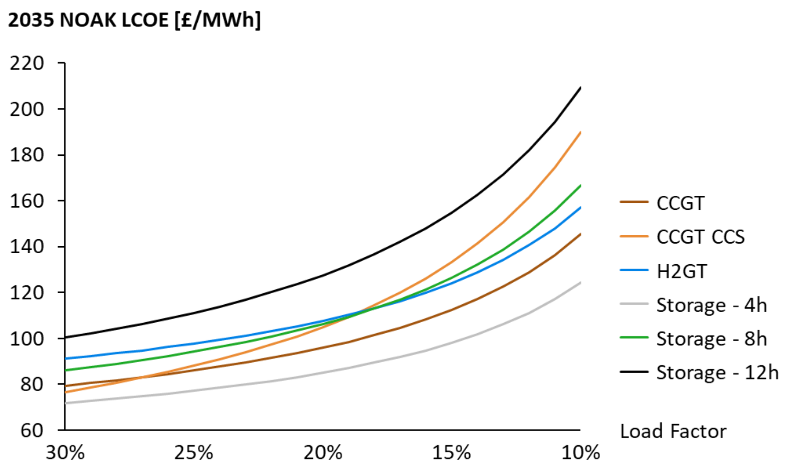


Figure 14: Change in LCOEs of NOAK peaking technologies with load factor in USA

2.4 China

2.4.1 Key drivers of recent power market evolution

Unlike the other regions studied in this report, China's focus on power policy has been on adequacy, i.e. building sufficient capacity to supply growing demand. China's power demand more than quadrupled since 2000, making it the world's largest electricity consumer[32]. As shown in Figure 15, coal has been the technology of choice (65% of generation in 2017)[21] for the majority of added capacity due to domestic resource availability. Most of these coal plants were built in the last 15 years and are expected to have a total lifetime of 60 years.

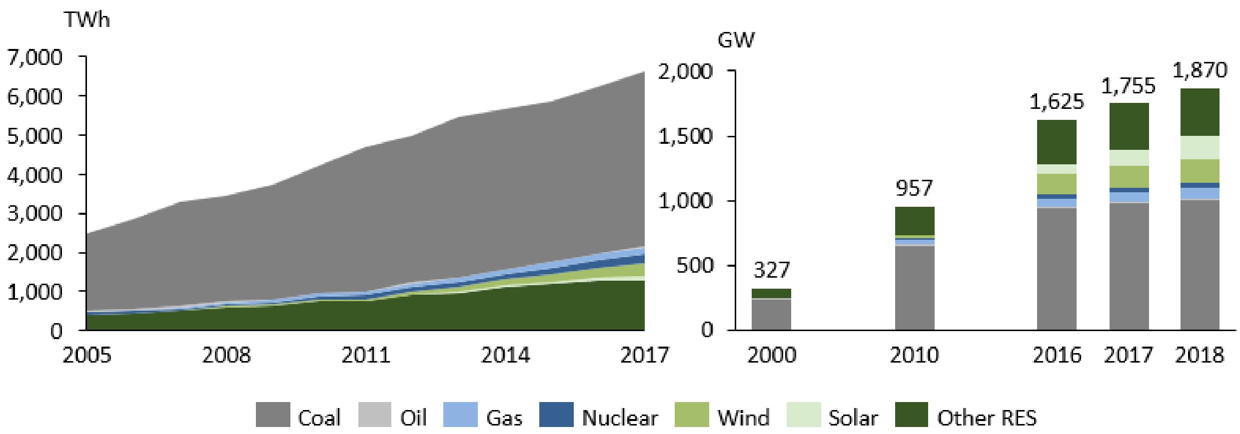


Figure 15: China breakdown of generation source (left)[21] and installed power capacity (right)[10]

The Chinese power sector is traditionally controlled by the central and local governments, with a lot of power plants built by state-owned enterprises (SOE). However, power markets are increasingly liberalised to improve commercial and economic efficiency. Currently a spot market is being tested in the Guangdong

[32] Power sector reform in China: an international perspective. IEA, 2018.

province and coal plants have been incentivised to operate more flexibly to accommodate wind and solar output[32]. There are also plans to introduce liberalised power markets in 8 regions representing 42% of total generation[33] and establishing financing instruments such as CfDs[34].

One of the important power sector drivers in China has been environmental impacts, particularly the increasing air pollution issues. China has been investing in cleaner coal plants and renewables (hydro energy heavy) for environmental reasons. The main policy instruments for the roll out of renewables have been the Renewable Energy Law and a series of five-year Renewable Energy Development plans[35]. Currently China committed to peak its emissions by 2030 the latest and achieve non-fossil fuel share of 20% in primary energy supply[36]. The government also considers an increased target of 35% of power consumption[37] supplied by renewables by 2035.

2.4.2 CCS in the power sector outlook

According to the WEO SDS China will produce 87% of its electricity from low-carbon sources by 2040 and, despite a 52% increase in demand, its coal fleet will be mostly replaced by gas, nuclear and renewables. As shown in Figure 16 below, more than a quarter of China's massive 1,000 GW coal fleet is expected to retire, while the rest is either retrofitted or operates flexibly. China is one of the only regions where retrofitting coal with CCS will be more economic than new gas CCS due to cheap domestic coal, the need to import natural gas and a large existing young coal fleet. Gas CCS is still needed to replace coal plants that are not fit for retrofits.

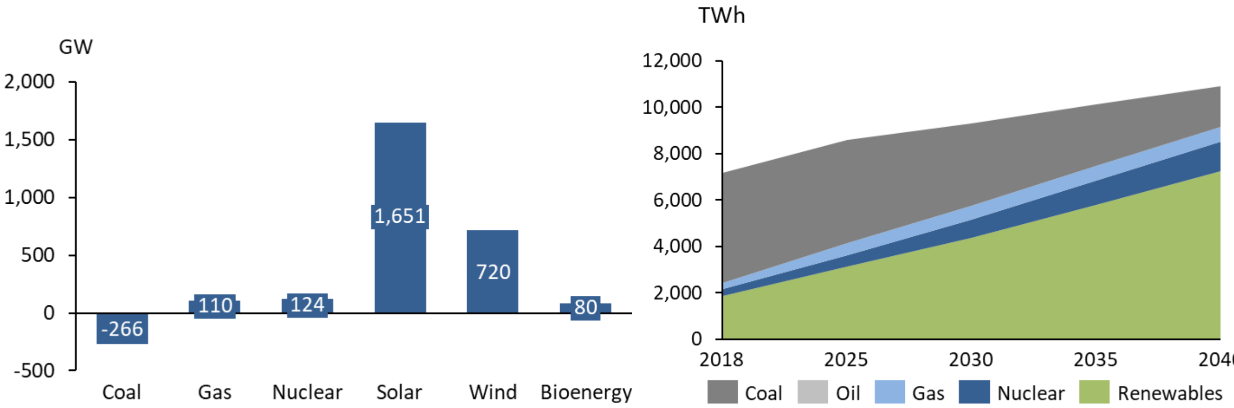


Figure 16: Net change in installed capacity (left) and power generation breakdown (right) for China between 2018-2040 in SDS

Table 6 summarises the CCS capacities and generation in the SDS. Like the USA analysis, load factors of CCS technologies are assumed to equal global averages. China is expected to have 75% of global coal CCS capacity alone, most of which (110 GW out of 125 GW) is projected to be from retrofits. A very large fleet of remaining unabated coal plants would reduce their load factors to an average of 18% from 54% today, to provide flexibility.

China is also expected to gradually shift towards gas in order to curb emissions. SDS includes a total of 31 GW gas CCS in China (as included in WEO 2018 edition), which represents ~20% of global gas CCS

[33] "China plans first spot electricity trading as Beijing reforms power market", Reuters, April 2018.
[34] Comments on National Energy Administration's "Advancing electricity spot market implementation". The Regulatory Assistance Project (RAP), 2019.
[35] China's renewable energy law and policy: A critical review. Junxia Liu. *Renewable and Sustainable Energy Reviews*, 99, p212-219. 2019.
[36] Assessing the policy gaps for achieving China's climate targets in the Paris Agreement. Gallagher, K.S., Zhang, F., Orvis, R. et al. *Nature Communications* 10, 1256 (2019).
[37] "China Steps Up Its Push Into Clean Energy", Bloomberg News, September 2018.

capacity. Together with coal, both CCS technologies would operate close to baseload generation with 67-69% load factors. Unabated CCGT plants on the other hand, are projected to assume a mid-merit generator role with an average load factor of 33%. The higher load factors of unabated gas plants compared to coal plants are a direct result of lower emissions of CCGTs.

Table 6: China 2040 projections of CCS capacities and load factors as interpreted from SDS[38, 39]

Fuel	Type	Generation	Capacity	Load Factor[40]
Coal	Unabated	991 TWh	615 GW	18%
	Retrofit CCS	~754 TWh	110 GW	69%
	New CCS		~15 GW	
Gas	Unabated	461 TWh	159 GW	33%
	Total CCS	~182 TWh	~31 GW	67%

2.4.3 Future role of CCS technologies

Please refer to appendix 1 for more detail on Capex, Opex and carbon price[41] assumptions for China.

Baseload generation

Figure 17 below summarises the LCOE analysis for baseload plants in China. CCGT CCS plants are cost-effective against counterfactual options starting from mid-2020s under these assumptions. Although H2GT costs are close to CCGT CCS, hydrogen is not expected to play a baseload role.

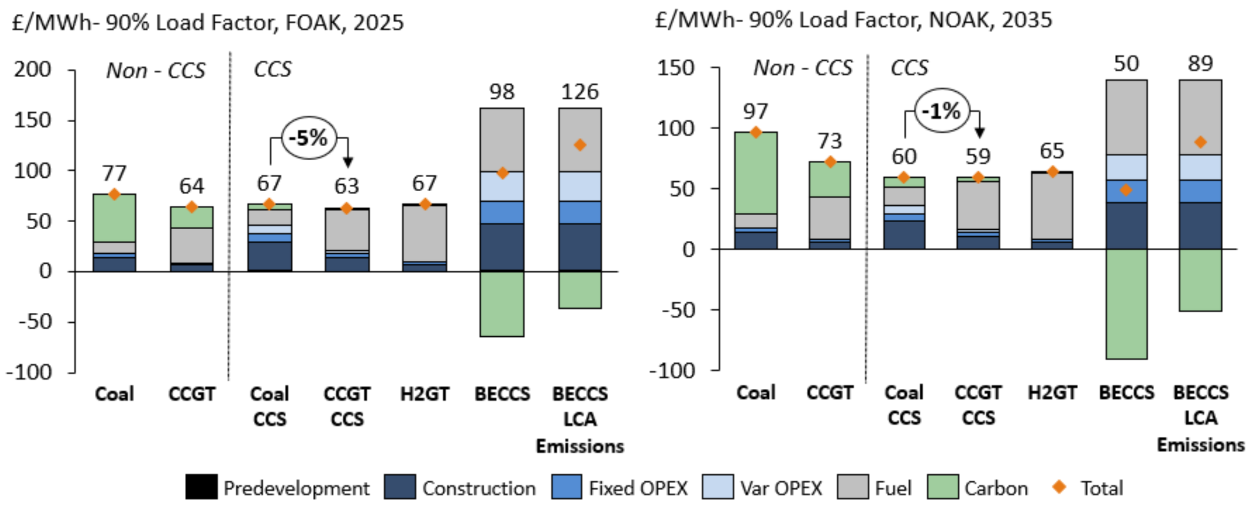


Figure 17: China- future LCOE comparison of technologies operating as baseload generators

[38] Gas generation and capacity data are calculated by using gas CCS generation data of WEO 2018 with CCS load factors of WEO 2019.
[39] WEO 2019 explicitly states the 110 GW coal CCS retrofit in China. New built coal CCS capacity is estimated depending on the global ratio of new built to retrofit coal CCS, which is 20 GW to 145 GW.
[40] Load factors are provided for the combined new and retrofit CCS fleet.
[41] Carbon price based on SDS (developing economies): £31.9/tCO_2 (2025), £74.2/tCO_2 (2035).

Coal CCS is also a viable option from mid-2020s, considering it has a similar LCOE to CCGT CCS and is projected to become more cost-effective in 2030s. China is the only region studied where coal CCS is cost competitive with other CCS technologies.

Lastly, BECCS costs span a wide range, which may establish it as the most competitive or expensive technology depending on the carbon accounting system employed. Considering that China is expected to produce 5.3% of its electricity from bioenergy in 2040 under the SDS, BECCS is likely to be deployed in most favourable locations and plants to benefit from negative emissions.

Mid-merit generation

Figure 18 left compares costs of NOAK mid-merit plants commissioning in 2035. Both CCGT CCS and H2GT are found to have the same lowest cost and are viable for mid-merit generation commissioning in early 2030s. However, the FOAK technologies are not competitive in 2025, and therefore CCS deployment for this medium capacity range would have to wait for higher carbon prices in 2030s. Also, a sensitivity analysis around load factors show that H2GTs start getting more economically feasible than CCS CCGTs for load factors less than 47%, therefore hydrogen may be a more viable choice for mid-merit generation if a higher level of flexibility is expected in the future.

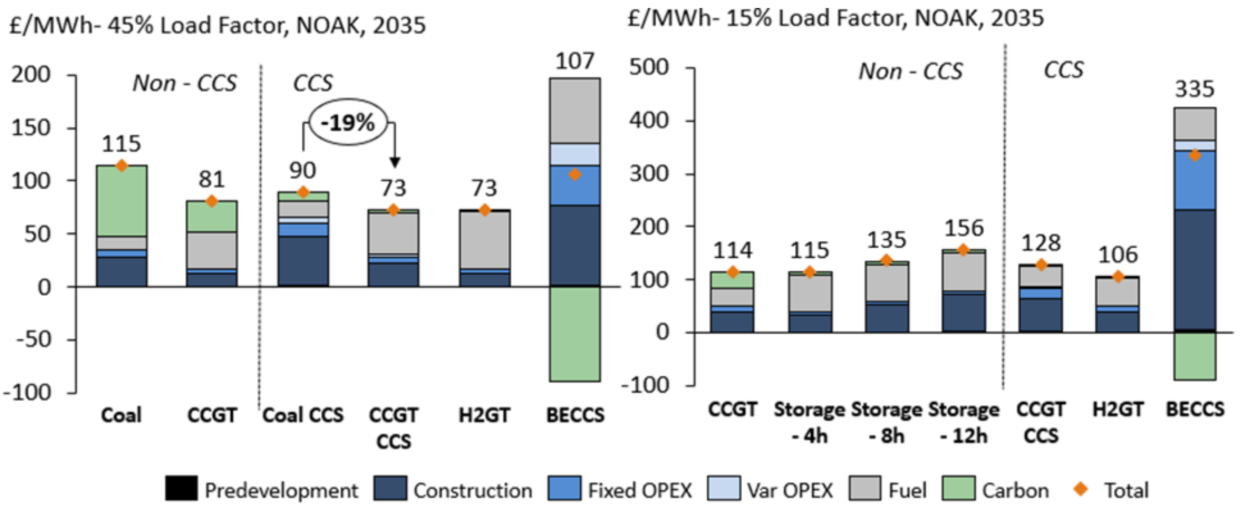


Figure 18: China- 2035 LCOE comparison of NOAK technologies operating as mid-merit (left) and peaking (right) generators

Peaking generation

As can be seen in Figure 18 (right), China is the only country studied where H2GTs are found to be cheaper than any other technology, for peaking generation, including batteries with a 4-hour discharge time. Even FOAK H2GT plants commissioning in 2025 are more cost-effective than all other technologies. The two main reasons for this finding are low hydrogen production costs (from gasification of cheap domestic coal) and relatively high industrial electricity prices, which increase battery fuel costs. Furthermore, relatively high imported natural gas prices in China increase CCGT LCOEs and positions hydrogen as a prime option.

Even though our analysis suggests that hydrogen for electricity generation is likely to be competitive from mid-2020s, H2GTs capable of burning 100% hydrogen are not currently available. Several manufacturers are making predictions[42, 43, 44] about developing such turbines in the second half of 2020s and we assume

[42] MHPS: https://www.mhps.com/special/hydrogen/article_1/index.html
[43] EUTurbines: https://www.euturbines.eu/publications/spotlight-on/spotlight-on-turbines-and-renewable-gases.html
[44] Siemens: https://new.siemens.com/global/en/company/stories/energy/hydrogen-capable-gas-turbine.html

that the large-scale hydrogen turbines with the same efficiency and Capex as CCGTs are not likely to be deployed before 2029-2030.

Retrofits

As mentioned earlier, China has a very large and young coal fleet, 110 GW of which is expected to be retrofitted with CCS by 2040 according to WEO SDS. A previous study[45] by IEA identified that 310 GW of coal plants (31% of the capacity, mostly on the Eastern parts of China) were identified to be retrofittable (Figure 19) depending on their age, proximity to storage resources, load factor and size.

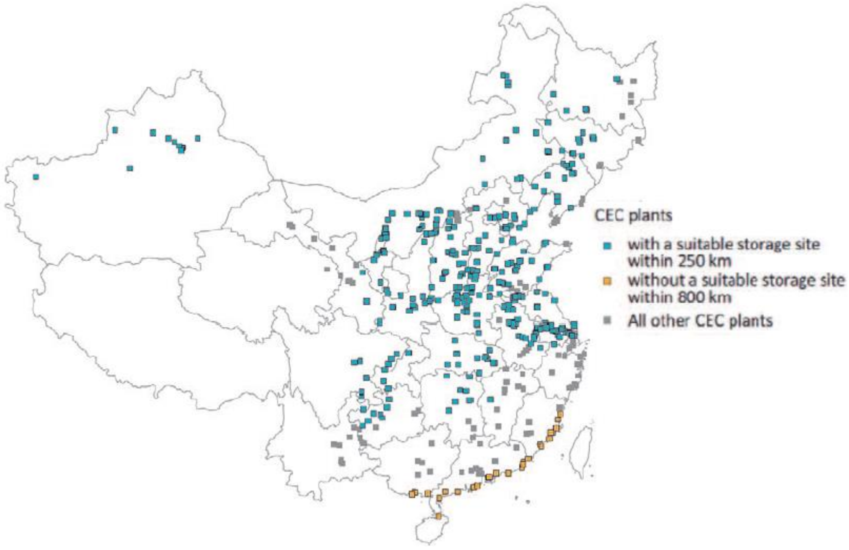


Figure 19: Map of CCS retrofit ready coal plants in China[45]

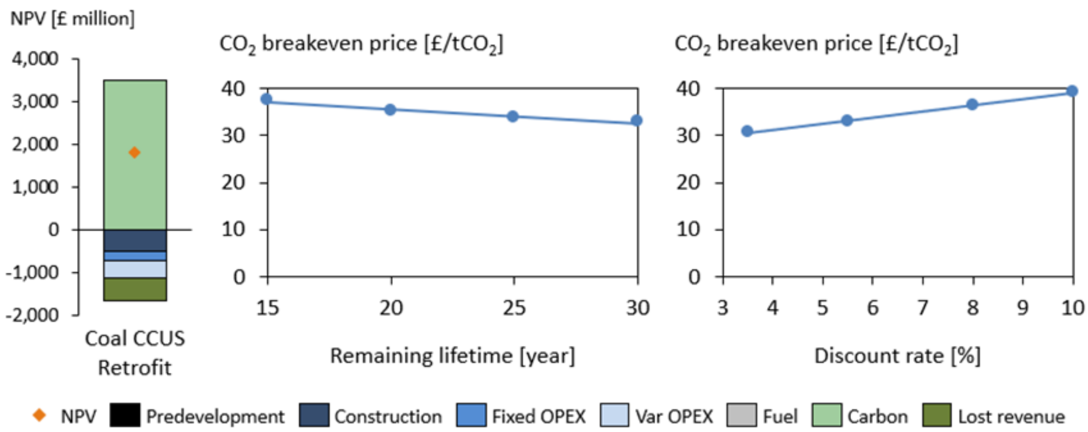


Figure 20: Present value of China coal CCS retrofit (left), retrofit breakeven CO_2 prices by lifetime (middle) and discount rate (right)

To investigate economic viability of retrofitting in China, a case study is undertaken following the analysis of another IEA Clean Coal Centre report[46] (please refer to appendix 1 for details). As can be seen in Figure 20 left, retrofitting a 1015 MW coal plant with a 30 year remaining lifetime operating at 57% load factor in

[45] Ready for CCS retrofit: the potential for equipping China's existing coal fleet with carbon capture and storage. IEA, 2016.
[46] Reducing China's coal power emissions with CCUS retrofits. IEA Clean Coal Centre, 2018.

2025 has a largely positive NPV under current carbon price assumptions and 5.52% discount rate. Furthermore, our sensitivity analysis shows that the average breakeven CO_2 price required decreases with remaining lifetime and increases with discount rate. This breakeven carbon price is in the 30-40 £/tCO_2 range, which is well below some ambitious projections, such as the SDS (£93/tCO_2 by 2040). Additional in-depth, plant-specific studies are needed to establish the economically viable retrofit potential in China, but coal to CCS retrofits are very likely to be an essential de-carbonization strategy for China.

2.5 Australia

2.5.1 Key drivers of recent power market evolution

Australia has rich fossil fuel resources therefore is a net natural gas and coal exporter. As can be seen in Figure 21, Australia relies heavily on coal and gas power generation[21], although share of renewables are slowly rising, due to the mandatory Renewable Energy Target, established in 2001 and currently running until 2030. Most recent capacity additions were wind, solar and battery, whereas retirements were mostly aging black and brown coal plants[47].

Australia has a very large capacity of rooftop PV instalments behind the meter, leading to system integration challenges. Moreover, major blackouts since 2016 demonstrated the threat of system security and triggered new investment in batteries and flexible solutions. Recently Australia also experienced very high domestic natural gas prices due to coupling of eastern domestic prices with the booming LNG export market. Although gas plants were deployed as the new dispatchable fleet, recent volatile fuel prices stalled further investments. Lack of competition among power retailers and high gas generation prices (which determine the marginal cost of electricity) are increasing wholesale electricity prices. In short, affordability, grid dependability and energy security are main drivers of the Australian power sector.

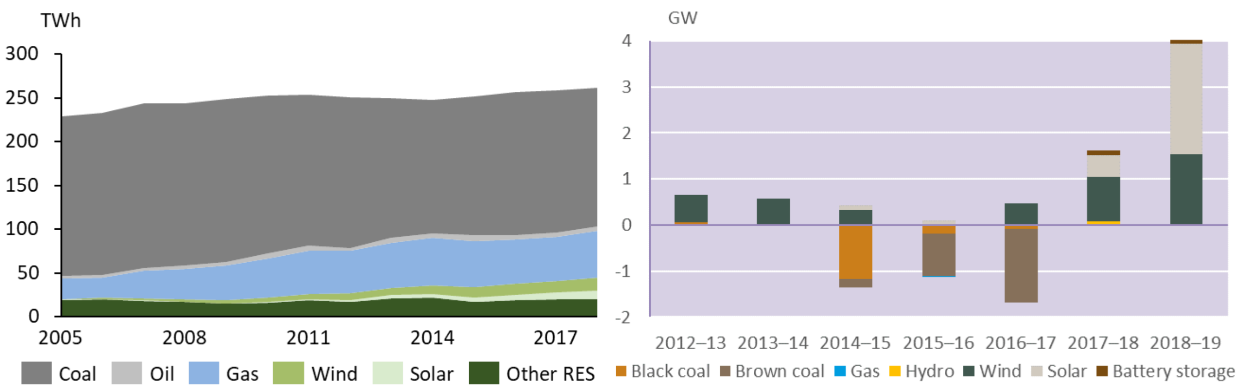


Figure 21: Australia power generation breakdown (left)[21] and change in installed capacity in the National Electricity Market (NEM, excludes Western Australia & Northern Territory) [47] (right)

Several national incentives and policies exist in Australia to help facilitate low-carbon technology uptake and ensure secure power supply (although currently none of them support CCS):

- Renewable Energy Target: Retailers must buy generation certificates to source a portion of their sales from renewable sources. The large-scale generation target is set at 33,000 TWh by 2020 and remains at that level until 2030. Currently there are no plans to extend it further.
- Emissions Reduction Fund: the government pays for emissions cuts through auctions. In 2018 less than 10% of the funds to 2020 remained. The scheme operates to provide low-cost abatement

[47] State of the energy market 2019, Australian Energy Regulator (AER).

opportunities. Only 2% of CO_2 abatement was from electricity projects as focus is given to non-power sectors.

– The new government policy includes the reliability component of the now ditched National Energy Guarantee, requiring retailers to contract enough dispatchable capacity in their portfolio.
– Small-scale renewable energy scheme and state-wide FiTs support distributed generation (solar PV, solar thermal, etc.).
– Clean Energy Finance Corporation invests in renewable energy (bioenergy, storage, wind, solar), built environment, agribusiness, green vehicles, innovative clean energy start-ups, etc.
– Australian Renewable Energy Agency (ARENA) invests in renewables projects and businesses.

2.5.2 CCS in the power sector outlook

The WEO and SDS does not include specific projections or figures for Australia, therefore regional power sector outlooks[48] developed by Commonwealth Scientific and Industrial Research Organisation (CSIRO) are used in this section. CSIRO's technology roadmap includes 4 possible scenarios focusing on (1) substantial energy efficiency improvements, (2) high renewables uptake, (3) dispatchable power capacity with renewables limited to 45% and (4) a combination of all options. Only the 3rd and 4th scenarios, as depicted in Figure 22 below, include CCS technologies.

The report acknowledges that CCS retrofits may be profitable, but results are highly situational and separate analyses would be required for each plant. Therefore, retrofits are omitted from the outlooks. Gas CCS is identified as the next most cost-effective option and plays a large role in scenario 3, where it generates a third of all power demand in 2050. This scenario includes a total of 17 GW gas CCS operating as baseload with a load factor of 82%. CSIRO notes that this level of deployment would most likely depend on low gas prices and large social acceptance of the technology.

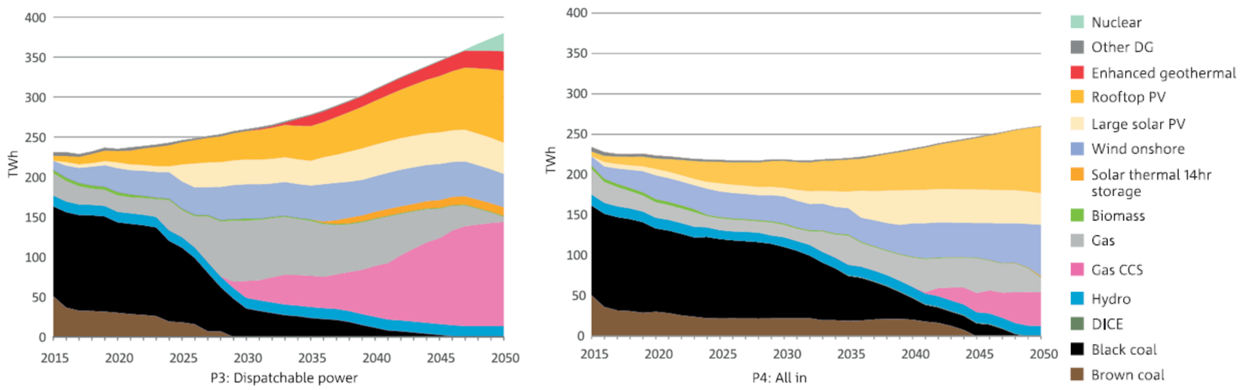


Figure 22: CSIRO's two power sector scenarios which include CCS technologies: scenario 3 (left), scenario 4 (right)

Scenario 4 adopts a more balanced approach, where total power demand is significantly lower than in scenario 3 due to overall efficiency improvements. A total of 7 GW of gas CCS are included which operates at 65% load factor in 2050 to generate ~16% of total demand. Except for the omission of coal CCS and retrofits, CSIRO's CCS projections are broadly consistent with WEO SDS forecasts in terms of load factors of initial plants and their role as baseload generators.

[48] Low Emissions Technology Roadmap. CSIRO, June 2017.

2.5.3 Future role of CCS technologies

Please refer to appendix 1 for more detail on Capex, Opex and carbon price[49] assumptions for Australia.

Baseload generation

As summarised in Figure 23, CCGT CCS plants are found to be cost-competitive with their unabated counterparts starting from mid-2020s for baseline operation. CCS technologies get progressively cheaper in 2030s with higher carbon prices and learning curves. Although coal CCS and hydrogen plants are projected to have lower costs than unabated coal plants, they are not expected to provide new built baseload capacity since CCGT CCS plants have substantially lower LCOEs. Lastly, minimum estimations of BECCS costs suggest that the technology is not likely to be economically viable compared to unabated CCGTs or CCS CCGTs. Still, a modest capacity of negative emissions may be deployed in Australia in the mid-2030s with a policy support higher than the carbon price used in our model.

Although a dedicated techno-economic analysis for CCS retrofits in Australia is not conducted in this report, there are studies[50] suggesting that brown and black coal CCS retrofits may have competitive LCOEs with solar PV in Australia. Further site-specific analysis is required to investigate the true CCS retrofit potential.

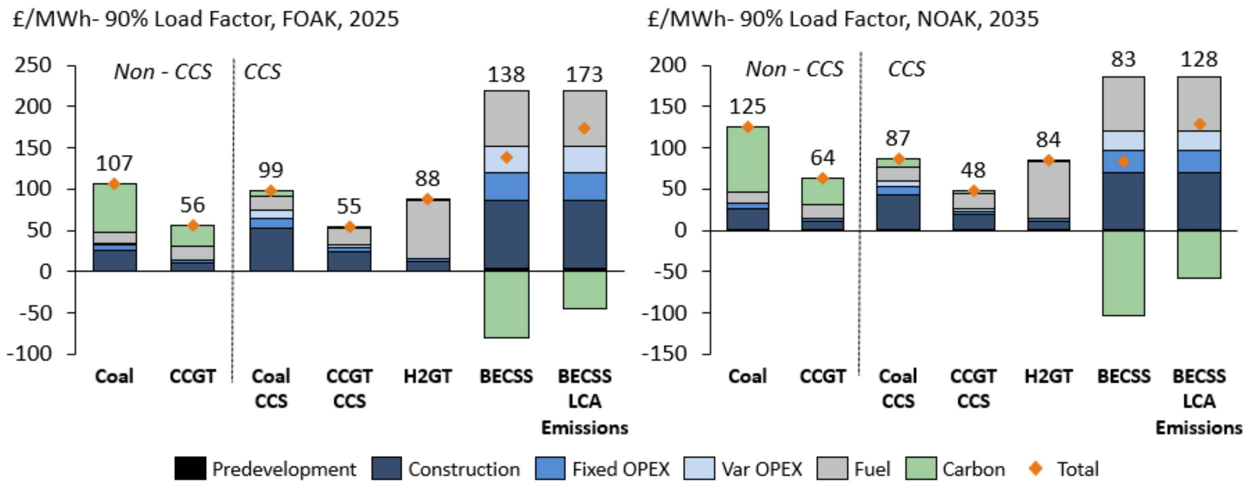


Figure 23: Australia- future LCOE comparison of technologies operating as baseload generators

Mid-merit generation

None of the mid-merit CCS technologies studied were economically viable as a FOAK plant commissioning in 2025, however as seen in Figure 24 (left), NOAK CCGT CCS is able to replace its unabated CCGTs as the most cost-effective option for mid-merit operation, which hold true for load factors higher than 34%. Other CCS technologies are not expected to be viable for medium load factors in Australia.

Peaking generation

The techno-economic analysis of Australian peaking plants (Figure 24 right) is very similar to that of the USA in the sense that H2GTs are the cheapest CCS option, which are competitive with batteries with 8 hours or more discharge time but are more expensive than unabated CCGT plants. Hydrogen is positioned to be the lowest-cost CCS technology for load factors below 18% but would require policy support beyond the modelled carbon price here to make it a viable investment over unabated CCGTs.

[49] Carbon price based on SDS (advanced economies): £46.4/tCO_2 (2025), £89.0/tCO_2 (2035).
[50] Retrofitting CCS to coal: enhancing Australia's energy security. CO2CRC & Gamma Energy Technology, 2017.

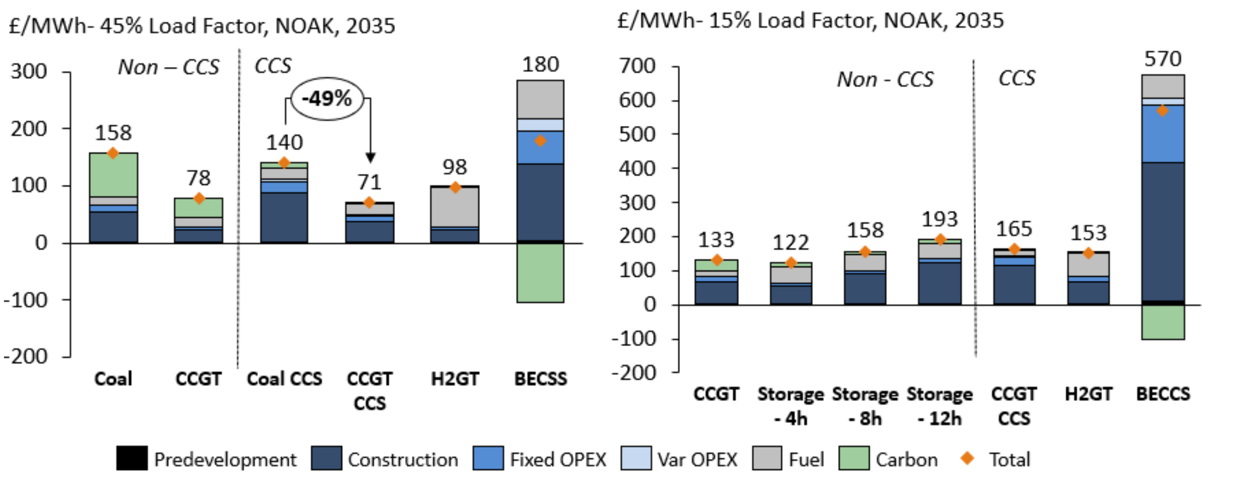


Figure 24: Australia- 2035 LCOE comparison of NOAK technologies operating as mid-merit (left) and peaking (right) generators

Sensitivity analysis with higher gas prices and longer project lifetime of coal

To assess the impact of changing fuel prices on the comparison of coal CCS and CCGT CCS plants, a sensitivity study was performed in which the gas price was varied. In recent years, gas prices in Australia offered to commercial and industrial consumers had increased significantly, due to the coupling of domestic gas and LNG export prices in the eastern market and higher gas prices offered in the Asian LNG market.

While prices for industrial and commercial consumers were at about AUS$4-5/GJ in 2015, they rose to up to AUS$22/GJ in 2017, decreasing back to AUS$8-11/GJ in 2018 after intervention by the government[51]. In 2019 domestic gas prices in Australia have decreased further, along with Asian LNG prices. However, the future of gas prices is uncertain and prices might start to rise again due to demand growth catching up with supply[52]. Therefore, a sensitivity analysis has been conducted using a gas price of AUS$10/GJ versus AUS$5.4/GJ in the base case (in 2018 real terms and in terms of HHV).

Figure 25 shows the impact of the higher gas price for CCGT CCS FOAK plants in 2025 and NOAK plants in 2035 in the case of baseload operation (90% load factor). The CCGT CCS costs are compared to those of a coal CCS plant in both cases. The gas price increase by 82% leads to an increase of the LCOE of CCGT CCS plants by 35% in the case of FOAK plants and by 42% in the case of NOAK plants. In both cases the LCOE of coal CCS plants are still considerably higher than those of CCGT CCS plants, even when the higher gas price is assumed. However, the premium of coal CCS plants is reduced significantly (halved in the case of NOAK plants).

As a further sensitivity study, the impact of the longer technical lifetime of coal plants vs CCGT plants (40 years vs 30 years[53]) has been assessed. While throughout this report a consistent financial lifetime of 25 years for generation technologies has been assumed for coal plants and CCGTs, in line with recent government reports[54], in the sensitivity study, a financial lifetime of 40 years for a coal CCS plant is used. Figure 26 shows the LCOE coal CCS plants when assuming a 25-year lifetime and a 40-year lifetime and compares them to those of a CCGT CCS plant when assuming the high gas price described above.

[51] State of the energy market, p. 208. Australian Energy Regulator, 2018.
[52] https://www.forbes.com/sites/woodmackenzie/2019/10/15/gas-prices-are-falling-but-australias-east-coast-gas-market-shouldnt-get-too-comfortable/#2f906b806f1f
[53] Fraunhofer ISE, 2018, *Levelized Cost of Electricity Renewable Energy Technologies*
[54] BEIS, 2018, *Electricity Generation Costs*; Wood, 2018, Assessing the Cost Reduction Potential and Competitiveness of Novel (Next Generation)

It can be seen that the longer lifetime has little impact on the LCOE, reducing e.g. NOAK LCOE by only 3%. This is due to the discounting of generation in later years in the LCOE calculation (note that a 10% discount rate is used throughout the report). The CCGT CCS LCOE are still significantly lower, even when a high gas price and a longer lifetime of coal CCS plants are assumed.

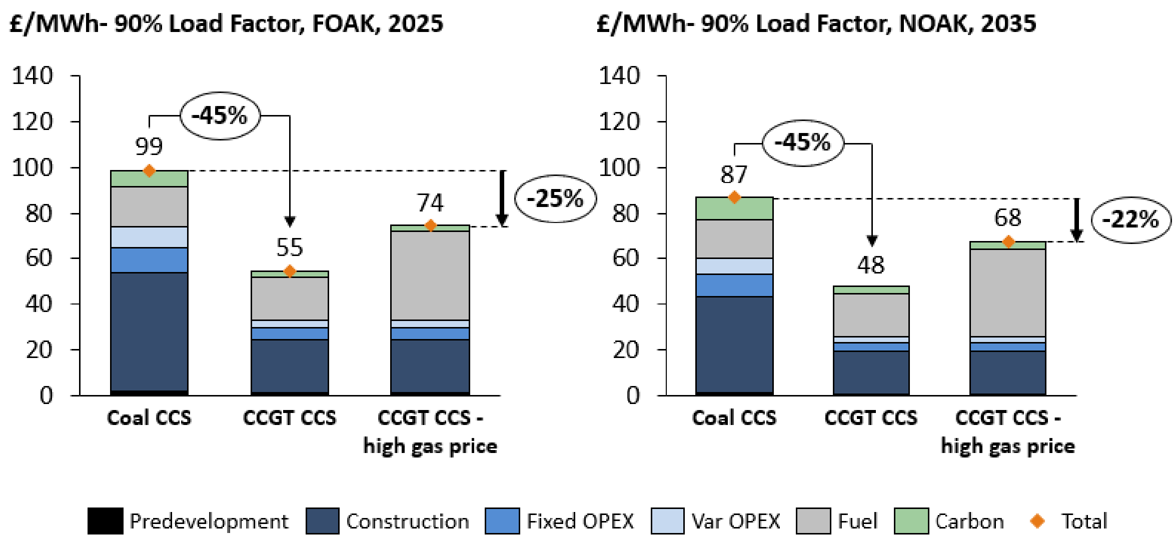


Figure 25: LCOE of coal CCS and CCGT CCS at 90% load factor with sensitivity of higher gas price; left graph: FOAK plants installed in 2025, right graph: NOAK plants installed in 2035

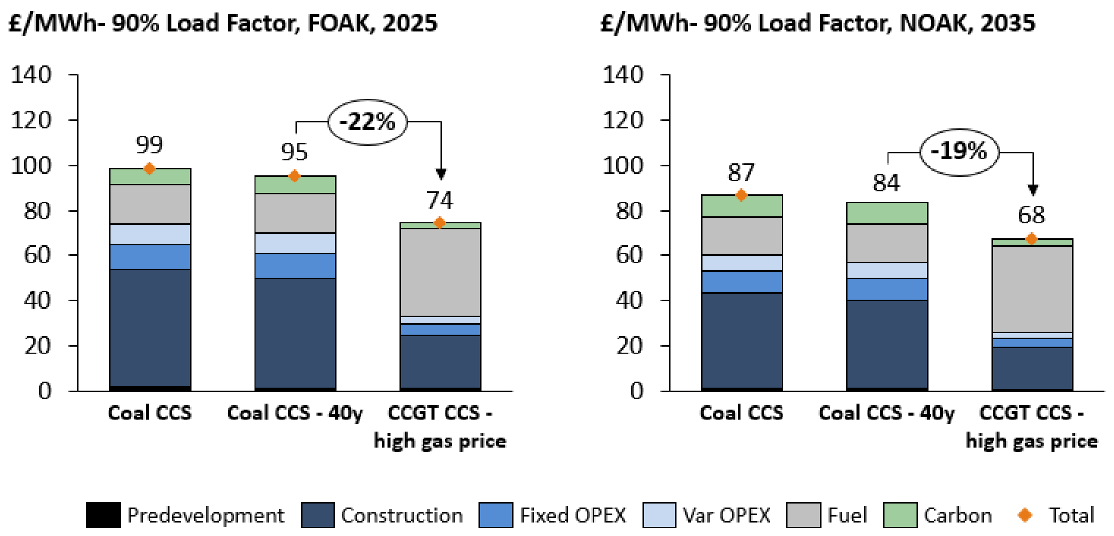


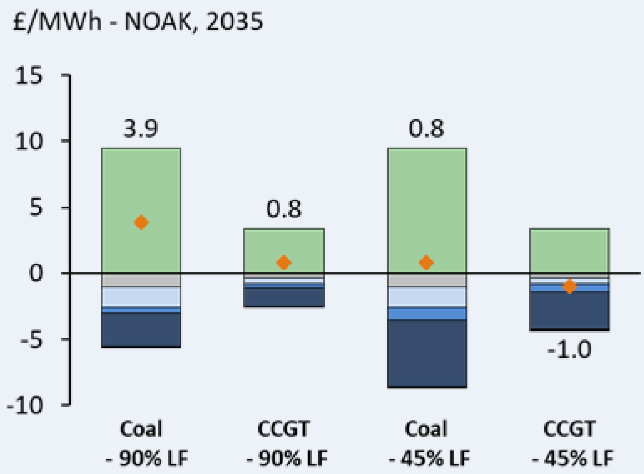
Figure 26: LCOE of coal CCS and CCGT CCS at 90% load factor with sensitivity of a 40 year lifetime of the coal CCS plant; left: FOAK, installed in 2025, right: NOAK installed in 2035

Box 2: A case study on using higher capture rates for zero-emissions CCS plants

Most CCS studies, reports, and engineering projects utilise an assumption of capturing 90% of CO_2 emissions from power plants. This 90% ratio is an arbitrary target which represents an understanding of the trade-off between environmental benefits of capturing more CO_2 and increasing costs of doing so. Although these CCS plants still have residual carbon emissions, technically it is possible to increase capture rates to sufficient levels to have zero emissions fossil fuelled power plants.

Recently IEAGHG published a report[55] studying technical and economic implications of increasing capture rates for eliminating residual CCS emissions. The report found that increasing capture rates to 99.7% for ultra-supercritical coal plants and 99% for CCGTs eliminated all emissions caused by combustion, i.e. the only CO_2 emitted is that in the incoming combustion air. Constructing and operating CCS plants at these higher capture rates increased average LCOE's of both coal and gas CCS plants by an additional 7% compared to 90% capture.

In order to investigate the effect of high capture rates, we have developed a case study where LCOE components of NOAK coal and CCGT plants commissioning in 2035 in Australia were modified according to the IEAGHG report. Please see appendix 1 for further details on calculations. Figure 27 below shows the change in LCOE components when going from a traditional 90% capture rate to net-zero emissions. Positive values represent cost savings and negative values show higher expenses. In all cases increased costs are partially offset by further carbon cost savings. It was found that both technologies had reduced average costs when operating at a 90% load factor, however, only coal CCS experienced costs savings at 45% load factor. Even CCGT CCS at 45% load factor only had its LCOE increase by a mere £1.0/MWh, which is a small change compared to its LCOE at 90% capture rate, £71/MWh.



This quick case study shows that higher capture rates may be a cost-effective option for deeper de-carbonization targets, but the body of scientific research in this field is still scarce. Furthermore, these initial findings must be confirmed in field tests to achieve higher confidence levels. Several other concerns, such as compatibility of high capture rates with flexible CCS operation and potentially cheaper zero-carbon options (offsetting, biomass co-firing, etc.) need to be investigated before a definitive conclusion can be made about the viability of high capture rate plants.

Figure 27: LCOE difference between CCS plants with 90% capture rate and plants with higher capture rates (net-zero emissions) for different load factors (LF) in 2035.

[55] Towards zero emissions CCS in power plants using higher capture rates or biomass. IEAGHG, 2019.

2.6 Summary of key messages from techno-economic analysis

The key roles of different CCS technologies that emerge from the techno-economic analysis are collated for each country and are presented in Figure 28 below. Some of the broader emerging messages are:

- Both coal and gas CCS technologies are cheaper than their unabated counterparts for baseload and mid-merit generation across the regions. Contrary to the common narratives, gas CCS is found to be more cost-effective than coal CCS in all situations except for baseload generation in China in 2030s, where both have similar costs.
- Gas CCS is calculated to be a competitive baseload option from as early as 2025, thus there is no reason to postpone encouraging CCS deployment, which would most likely run as baseload initially.
- Also, gas CCS is the most viable technology for mid-merit generation due to alternatives being more expensive. However, mid-merit CCS economics become viable only in mid-2030s when the carbon price rises to sufficient levels.
- As for peaking generation, H2GTs have a unique role in providing backup for sustained periods (>8 hours) of high demand in 2030s. Battery storage is likely to be the cheaper option for shorter periods.
- BECCS may be economically viable with the modelled carbon price in the UK and China, but is likely to require varying levels of additional support in the USA and Australia. Due to strategic importance of negative emissions at least modest levels of BECCS deployment is expected in all regions.
- Retrofitting gas plants with CCS/hydrogen and coal plants with CCS/biomass/BECCS may be a viable strategy for fossil fuel dependent countries. The ultimate decision to retrofit would be very case specific and each plant would have to be analysed separately before making a decision.

In light of these observations about the role and potential of CCS technologies, the following sections will investigate policy mechanisms which can help reach these desired deployment levels.

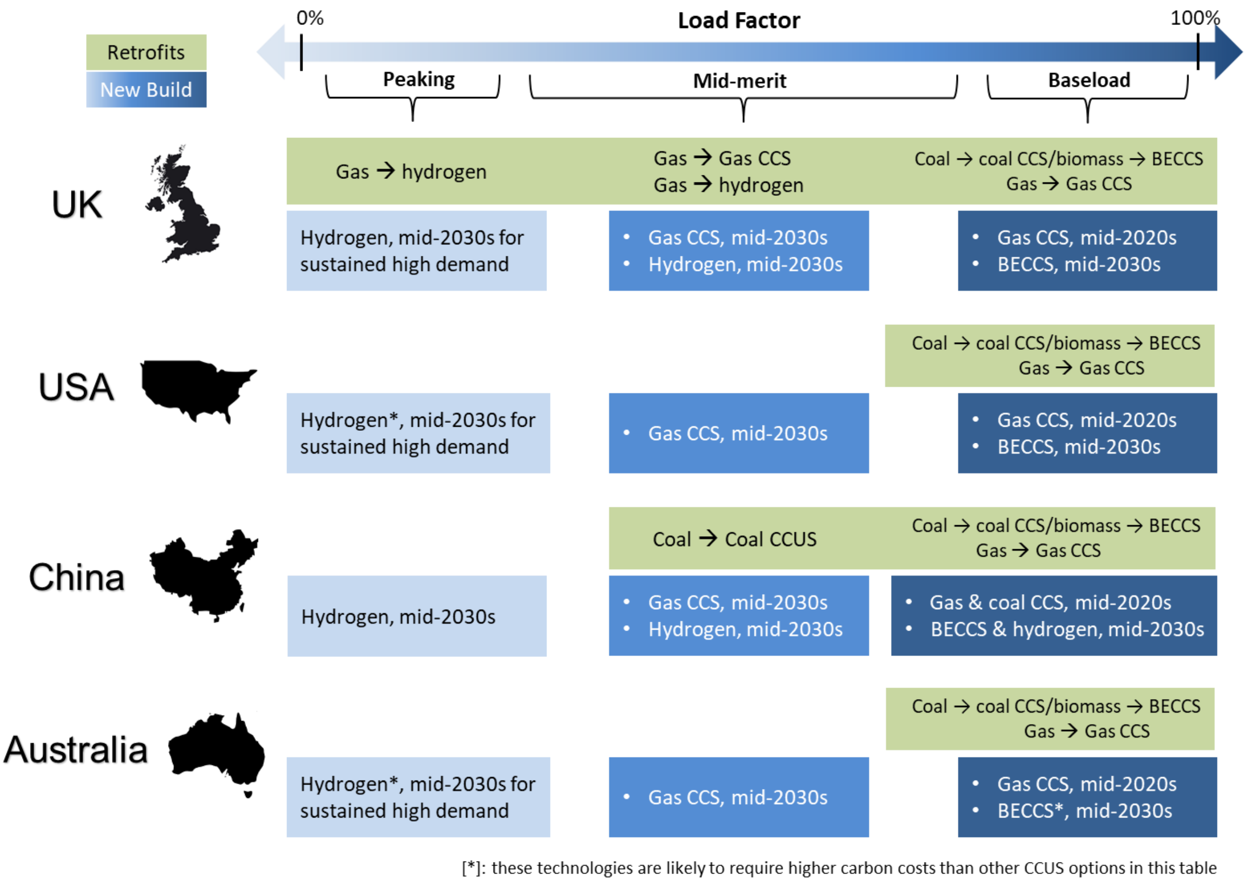


Figure 28: Summary of key CCS roles and timelines for each region

3. General and regional policy mechanisms to support power CCS deployment

3.1 Learnings from past power CCS projects

As discussed in the introduction section of this report, current deployment rates of power CCS technologies are far behind capacities required in most future climate scenarios. According to the CO_2RE database[56] of the Global CCS Institute (GCCSI) most of the global large-scale CCS projects are not in the power sector and currently there are only 2 operational large-scale power CCS projects.

Understanding the reasons for this disparity between required and deployed capacities is paramount to ensure the success of future projects and to develop effective policies to incentivise further uptake. In order to determine success and failure factors associated with power CCS deployment, case studies are developed for 8 projects (see Figure 29) that are either operational or discontinued for various reasons:

- The two operational projects: Petra Nova and Boundary Dam
- Discontinued projects in USA: FutureGen 2.0, Kemper County and Texas Clean Energy Project
- The two discontinued candidate projects for the £1 billion UK CCS commercialisation programme which was cancelled in 2015: White Rose and Peterhead
- Rotterdam Capture and Storage Demonstration Project (ROAD), The Netherlands

Appendix 2 includes the full case studies which specify project characteristics, commercial arrangements, business plans, key drivers and success/failure factors. Key learnings from the case studies are collated and presented in Table 7 below.

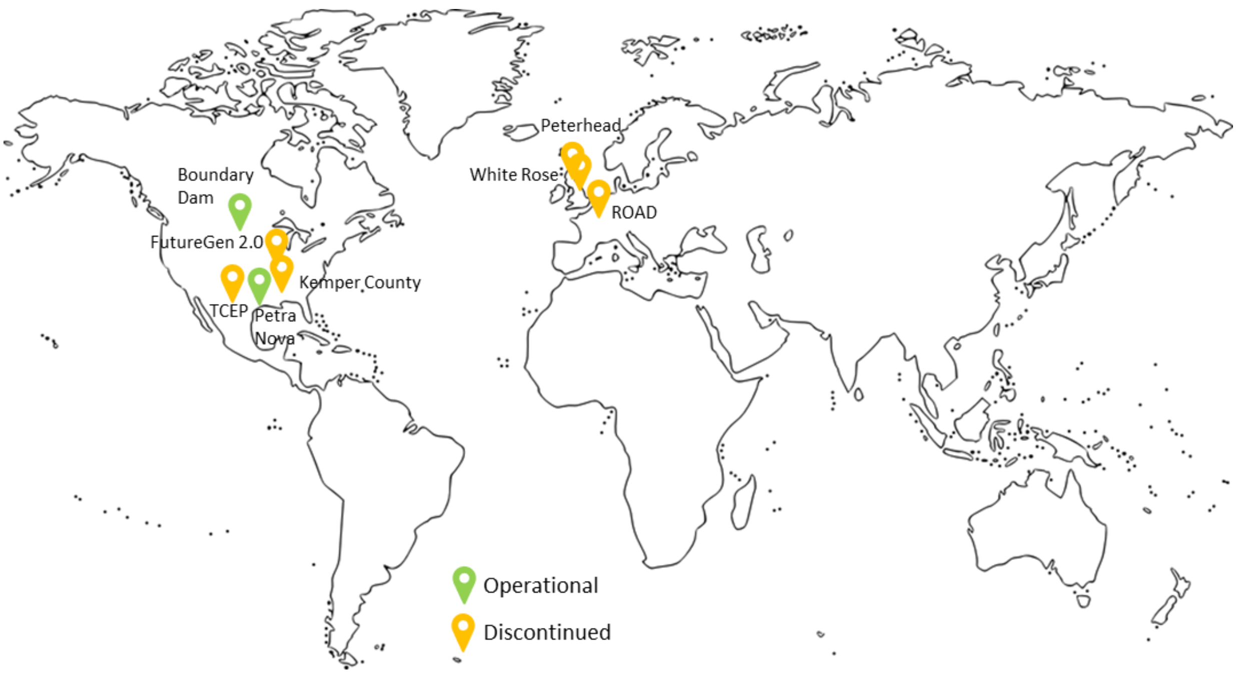


Figure 29: Map of successful and discontinued power CCS projects reviewed in this study

[56] CO_2RE CCS Facilities Database, GCCSI. Accessed 21st November 2019. https://co2re.co/FacilityData

Table 7: Summary of learnings from reviewed power CCS projects

Success Factors	Failure Factors
• Vertical integration of the total CCS value chain • CO_2 utilisation options, specifically EOR, for guaranteed revenues • Early government grants, especially for storage appraisal and early project development before final investment decision (FID) is made • Reducing project costs through utilising existing infrastructure, which would otherwise be decommissioned • National emission reduction targets, sector specific caps or phase-out of certain technologies, i.e. unabated coal • CfDs or other similar policy incentives providing stable revenues	• Long-term, uncapped storage liabilities, lack of favourable regulation for liability and un-insurability of project liabilities by financial institutions[57] • Cross-chain default risks • Constant policy shifts and lack of dedicated policy support • Business models depending on dynamic revenue streams (like EU-ETS) suffering from risk of low carbon costs • Lengthy permitting and regulatory processes prolonging project timelines and increasing costs • Incorrect predictions of future fossil fuel prices • Lack of commercial arrangements for oversizing initial T&S infrastructure • Highly prescriptive and inflexible governmental support programme requirements • Possibility of decreasing oil well production performance reducing revenues from EOR • Attempts to deploy novel/less mature technologies rather than more established options at scale • Lack of detailed understanding of the technology in the financial sector

3.2 Global policy and regulatory suggestions to promote CCS

Considering the above learnings from CCS projects, a brief literature review[13,58,59,60,61,62,63,64] was conducted to determine the main barriers for power CCS technologies and policy incentives that may overcome these barriers. Almost all the reviewed studies/reports acknowledge that the largest barriers stopping large-scale adoption of CCS are very high initial Capex requirements and lack of a consistent mechanism to generate revenues (recovering Opex). Options to mitigate these two issues are summarised in Table 8 below. The applicability of these policy incentives to specific countries and CCS technologies would depend on specific circumstances, which will be further investigated in following sections.

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[57] Storage liability refers to the liability of CCS project developers or storage companies in case of leakage from the storage site. Currently many regulatory regimes do not cap this liability. For example, the EU CCS Directive requires companies to pay an amount of money equal to the mass of CO_2 escaped times the carbon price in the EU ETS at the time of leakage. This means that liabilities would be difficult to predict because the carbon price is dynamic. Also, banks and other institutions are not willing to insure CCS projects as liabilities may be many times the total project cost, which could bankrupt any company if it actually had to be paid.
[58] Policy priorities to incentivise large scale deployment of CCS. GCCSI, 2019.
[59] Five keys to unlock CCS investment. IEA, 2017.
[60] An assessment of CCS costs, barriers and potential. Budinis, S., Krevor, S., Dowell, N., Brandon, N., Hawkes, A. 2018. Energy Strategy Reviews, (22), p 61-81
[61] An Executable Plan for enabling CCS in Europe. Zero Emissions Platform (ZEP). 2015.
[62] Working paper 2: Financial Incentives for the Acceleration of CCS Projects. Greig, C., Baird, J., Zervos, T. University of Queensland, 2016.
[63] Lessons and perceptions: adopting a commercial approach to CCS liability. GCCSI, 2019.
[64] Business models for CCUS: A consultation seeking views on potential business models for carbon capture, usage and storage. BEIS, 2019.

Table 8: Summary of policies, incentives and actions available for governments and project developers to support CCS deployment

High CAPEX	Lack of OPEX Recovery
CCS requires high upfront capital investment, even before an FID is made, which takes a long time to start payback	CCS projects lack a consistent mechanism to earn revenues due to low value put on captured CO_2, except when used for EOR
Potential Solutions	**Potential Solutions**
1. Capex-based tax credits to alleviate tax liabilities and ease project finance 2. Direct public procurement 3. Capital support through government grants, tax-exempt financing, concessional loans, accelerated depreciation or direct equity investment. 4. Cheaper finance through progressive financing, international financing institutions or export credit agencies.	1. Operational tax credits to increase profitability. 2. CCS obligations with tradeable certificates: each retailer must source a minimum portion of its electricity from CCS. 3. Emissions Performance Standards (EPS) with tradable CCS certificates: each retailer must source a minimum portion of low carbon power. 4. FiTs per unit of electricity or captured CO_2. 5. Contract for Difference (CfD): Plants are guaranteed a fix amount of revenue per kWh or tonne CO_2 stored through topping up spot market prices. 6. Top up on revenues through CO_2 utilisation, i.e. EOR, carbonated beverages, glasshouses, buildings, plastics, fuels, etc.

The suggestions listed in Table 8 apply to CCS capture and power generation companies, however special consideration must be given to T&S services too, which are likely to be separate companies and provide services for multiple CCS projects from different sectors. T&S infrastructure costs may be significantly reduced by forming CCS clusters, oversizing initial assets and utilising existing assets which would otherwise be decommissioned. Furthermore, governments may deploy T&S infrastructure through state owned models or some form of a Regulated Asset Based (RAB) model where a regulator monitors all the spending of T&S companies and determines the amount of service fees they can charge, which is ultimately paid by consumers and/or tax payers. These models currently work well at delivering projects with monopoly utilities in the UK, and each country may adopt a similar policy depending on their preference.

In addition to the Capex and Opex related restrictions, several other barriers and risks were identified during the literature review. A non-exhaustive list of these barriers and proposed solutions or recommendations to overcome them are provided in appendix 3, as they are outside the scope of this report.

3.2.1 Flexible operation

Initial CCS power plants are likely to operate as baseload generators in order to maximise their positive contribution to the system as low-carbon sources. However, there are two reasons why CCS plants are expected to run more flexibly (at lower load factors) in the long term:

1. As the share of variable renewable energy increases, there would be less room to accommodate baseload generation and rest of the power fleet would have to provide flexibility services for successful integration of renewables.

2. Traditional CCS plants with 90% capture rate still have some residual emissions, which become difficult to justify with net-zero scenarios or stringent sustainability targets (although increasing capture rate to ~99% or co-firing biomass could tackle this problem).

The idea of CCS plants operating flexibly in the future is reinforced by projections of reducing load factors for gas and coal power plants in power outlooks, such as the WEO, as well as the CCC Net-zero report[26], which explicitly states the need to build 1-2 GW/year gas CCS plants with a load factor of 20-25% in the UK from 2030 to 2050.

Although the need for flexibility is apparent, and CCS technologies seem to be technically capable of providing flexibility[65,66], global discourse around incentivising flexibility is almost non-existent. Most of the policy mechanisms currently discussed for CCS support- such as CfD, FiT, tradable certificates and tax credits- encourage baseload generation by rewarding benefits based on units of electricity output or CO_2 storage. Flexible plants, on the other hand, require incentives for staying idle over long periods and operating briefly in key moments.

Some electricity markets, including the UK, have capacity markets or other mechanisms to bank extra power generation capacity or load reduction services to be used at times of emergency. Contracts are awarded through auctions and generate a small revenue for plants over time for maintaining that capacity. Capacity markets can be accessed by CCS plants, but current payments are too low to justify flexible CCS operation or construction of new plants, despite alternatives generally being high emissions options. Therefore, specialised policies must be developed for CCS.

A study[67] commissioned by the UK government investigated market-based mechanisms to incentivise CCS and formulated a policy incentive for flexible operation, called flexible contracts for difference (CfD). The mechanism would consist of two components: a flat capacity payment for plant availability and a variable payment to incentivise flexible operation, as shown in Figure 30. Flexible CfD requires identifying a real or hypothetical unabated counterpart for the CCS plant. Then a detailed techno-economic model is used to calculate the short-run marginal cost (SRMC) of the unabated plant. Normally, fossil fuelled plants run only when the wholesale electricity price is higher than their SRMC. The flexible CfD tops up wholesale revenues of CCS plants to a pre-determined strike price only at times when the wholesale price is higher than the SRMC. In other words, flexible CfD is a regular CfD mechanism that only functions when an unabated fossil fuel plant is expected to run. This ensures that the merit order of the grid is not altered and CCS plants are given priority to run before other fossil generators, but not renewables.

Moreover, parameters of flexible CfDs can be updated over time to initially support higher load factor operations and transition to more flexibility in the long-term when the grid requires balancing due to increasing renewable share and cheaper flexible CCS technologies are developed.

The flexible CfD is just one single policy recommendation and needs experimentation and further analysis to ensure its effectiveness. It is also designed to work alongside regular CfDs, which other regions do not necessarily have. Therefore, future work must focus on developing more regional, robust policies for flexibility.

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[65] Operating flexibility of power plants with CCS. IEAGHG, 2012.
[66] US DOE recently (November 2019) announced a new $43 million fund for research and development of flexible CCS technologies focusing on both retrofits and new build plants. https://agenparl.eu/department-of-energy-announces-43-million-to-develop-carbon-capture-and-storage-technology/
[67] Market based frameworks for CCUS in the power sector. Cornwall Insight and WSP, April 2019.

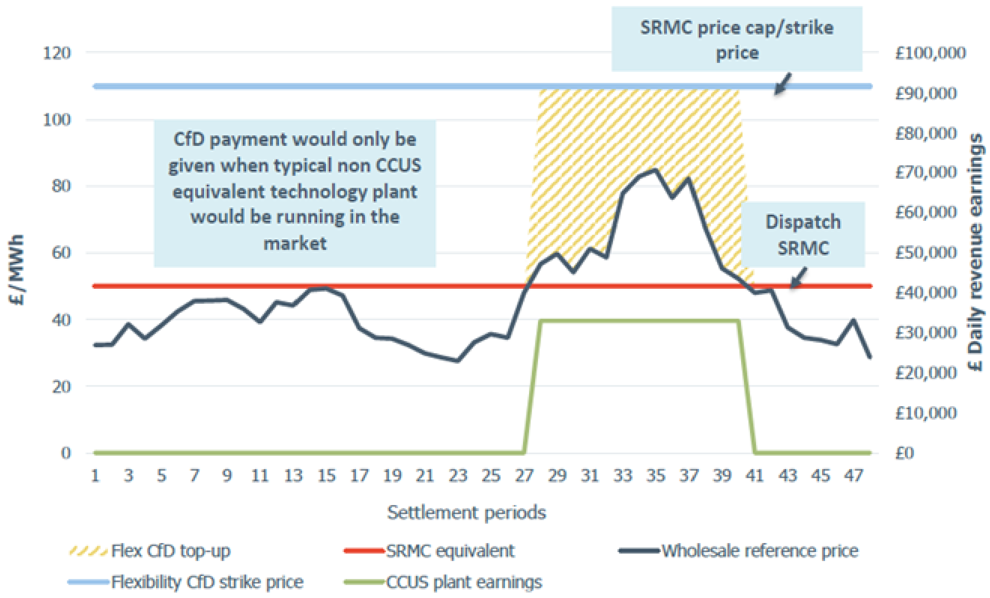


Figure 30: Representation of how a flexible CfD mechanism may work[67]

3.2.2 Hydrogen

Hydrogen, like natural gas, is an energy carrier which can be used for many applications such as power generation, transportation, industrial and domestic heating. Development of future hydrogen production, transport and storage infrastructure heavily depends on the extent to which hydrogen will be used in all these sectors; hence, an economy-wide approach must be taken when evaluating the feasibility of hydrogen in electricity production.

Hydrogen can be produced by using electricity and water, a process called electrolysis. If 100% renewable energy is used in the process, zero emission hydrogen (also called green hydrogen) can be produced. Electrolysis can be performed in any region with enough renewable energy, but the process is currently not the cheapest low-carbon hydrogen production option in most countries[68].

Coal gasification and natural gas reforming, in conjunction with CCS, can be used to produce hydrogen with low carbon footprint (also called blue hydrogen) from fossil fuels. These chemical processes are mostly mature and are already used (mostly without CCS) to produce the majority of today's hydrogen demand[69]. Blue hydrogen is currently the most effective low-carbon hydrogen production option in many regions[68], although some restrictions apply with regards to domestic fossil fuel availability and proximity to carbon storage sites. Biomass gasification can also be used to produce hydrogen, which has the potential to be net-negative if combined with CCS. It is also possible to blend a ratio of blue hydrogen with bio-hydrogen to drive hydrogen mixtures that have net-zero or net-negative emissions.

Hydrogen can be combusted in specially designed turbines, capable of flexible operation, much like current CCGTs. As discussed earlier, H2GTs capable of running on 100% hydrogen, without modifications, are not yet developed. Currently, a dedicated H2GT would either require a post-combustion NO_x separation unit or dilute the incoming hydrogen by steam or N_2 blending. These modifications would cost an additional 10-15% of a CCGT's Capex[16], but major turbine manufacturers[42,43,44] are confident in developing 100% hydrogen turbines which will not require such processes by 2030. Therefore, turbine availability is not likely to be a barrier in the medium term.

[68] The future of hydrogen: seizing today's opportunities. IEA, June 2019.
[69] https://www.iea.org/tcep/energyintegration/hydrogen/

Still, there are other risks, barriers and challenges relating to the hydrogen economy at large, which may affect the future of hydrogen for power[64]:

- Unsubsidised cost of low-carbon hydrogen production is expected to be higher than high-carbon emission options even by 2030, requiring continued incentives for sustainable hydrogen.
- Using hydrogen in power may depend on a larger societal shift towards a hydrogen economy, which would ultimately depend on hydrogen's performance in non-power sectors.
- Not all type of appliances have models that can easily use hydrogen, limiting large scale deployment in domestic and commercial spaces. Also, the one-off appliance conversion costs must be paid by the project developers, which may damage wider hydrogen adoption.
- Safety, feasibility and consumer acceptability of hydrogen for grid distribution and heating needs to be proven.
- Early hydrogen production investments have a demand risk, as it is difficult to foresee adoption levels, which makes sizing production facilities difficult: oversizing for cheaper future gas may leave assets stranded.
- Since hydrogen produced from different methods can be mixed and transported easily, accounting for the exact emissions intensity of hydrogen in a future high supply scenario would be difficult. Also, double counting hydrogen incentives, especially in case of imports/exports is a possibility.

Some of these problems may be addressed by[64]:

- Defining appropriate business models for low-carbon hydrogen production supply chain including use of hydrogen in power.
- Establishing robust measurement, monitoring and verification standards for hydrogen in order to track carbon intensities of hydrogen produced from all sources as well as imported hydrogen.
- Allowing H2GTs to be eligible for existing low-carbon power policy mechanisms considering supply chain emissions and interactions with other incentives.
- Including hydrogen production and distribution asset costs in regulated asset bases (RAB) of gas distribution network operators may incentivise hydrogen for heat.
- Focusing on and enabling hydrogen use in few key industries (such as power generation, petrochemicals, blending in gas grid) which have predictable and continuous demand can de-risk early investment.
- Resolving technical limitations such as safe grid blending capability and appliance conversion through targeted grants and subsidies for demonstration projects/competitions.
- Adjusting the level of abatement subsidies by providing a stable carbon price, which would protect investors from carbon price volatility, but also allow a future subsidy-free route to market as carbon prices increase to sufficient levels.
- Emphasising the advantages of hydrogen relative to natural gas to grow public support.

3.2.3 BECCS

Biomass, like hydrogen, is not a power-specific resource and can also be used to produce heat, biomethane, biofuels, etc. Unlike hydrogen, however, bioenergy is already used widely in many regions, such as the UK (7.4% of primary energy supply). BECCS requires deployment of CCS, therefore all the previous issues identified with CCS and potential recommendations will apply to BECCS too. Unlike other technologies considered, BECCS can also provide negative emissions, so may require special policies and regulations recognizing and accounting negative emissions to unlock its full potential.

In this regard, barriers and solutions surrounding BECCS are at the intersection of larger CCS, bioenergy and negative emissions sectors. Some barriers and challenges[70,71,72] for BECCS deployment are:

- As with the CCS technologies, the biggest barrier to BECCS is high costs due to biomass prices being higher than fossil fuels in the absence of subsidies or high carbon prices.
- Ensuring sustainability of biomass supply is a concern, especially for imported resources, since exporting countries may not require ambitious sustainability standards, which may lead to offshoring emissions.
- Negative emissions are not recognised in EU-ETS and many other carbon pricing schemes in the world.
- Accounting for the exact amount of stored carbon is difficult since each type and batch of feedstock may have different carbon content. Also, the supply chain contributes to the LCA carbon intensity of bioenergy, further complicating accounting.
- Resources devoted to domestic biomass production may interfere with food production, lead to land use changes or change of local ecosystems, which have environmental, political, economic risks, including public acceptability of land-based emissions reduction solutions.

Table 9: Recommendations and incentives to overcome barriers for BECCS deployment[70,71,72,73]

General Recommendations	Financial Incentives
• Large scale BECCS applications, such as power generation, may require biomass imports, which can be more sustainable than domestic resources delivered through road transport. • Installing and enforcing stringent biomass import sustainability criteria would help manage public perception and ensure that lowest carbon feedstocks are used. • Developing improved measurement, monitoring and verification (MMV) standards and regulations to increase accounting precision and trust. • Larger sustainable feedstock supply chains need to be established through government R&D support for energy crops, launching large scale supply chain demonstration projects and increasing energy from waste through better recycling schemes and higher landfill tax.	• Inclusion of BECCS in the EU ETS scheme (as well as other carbon pricing mechanisms) through Negative Emissions Allowances would be beneficial in the long-term when carbon costs increase to sufficient levels. • A dedicated Contract for Difference (CfD) mechanism for BECCS (both for electricity generation and industrial use) which rewards negative emissions separately[74]. • A greenhouse gas removal (GGR) obligation scheme may require companies to buy certificates to offset an increasing portion of their emissions. This would incentivise BECCS along with other GGR technologies. • A tradable tax credit scheme covering both the capital costs and awarding £/tonne CO_2 incentive. Burden on the public can then be alleviated by using a carbon levy tax. • In the short-term, direct government subsidies and grants can be effective to establish initial BECCS plants.

70 Greenhouse gas removal (GGR) policy options. Vivid Economics, 2019.
71 Going negative: policy proposals for UK bioenergy with carbon capture and storage (BECCS). REA, 2019
72 Delivering the UK's Bioenergy Potential: Key actions for realizing bioenergy's essential role in getting to net zero. REA, 2019.
73 Generating negative emissions with bioenergy. Samuel Stevenson (REA). *Energy World*, Dec 2019.
74 Beyond "net-zero": a case for separate targets for emissions reduction and negative emissions. McLaren et al. Front. Clim. 1:4, 2019.

3.2.4 Retrofits

Existing coal or gas fired plants can be retrofitted with CCS, which involves adding a capture plant on site and connecting to a T&S infrastructure. The 2 active large-scale power CCS projects today (Boundary Dam and Petra Nova) are both retrofits to existing coal plants. It is also possible to retrofit a power plant with hydrogen, which requires modifications to the turbine and/or blending with either nitrogen or steam. Equinor, Vattenfall and Gasunie signed a memorandum of understanding to convert one of the 440 MW gas turbines of the Magnum power plant in Eemshaven in the Netherlands to run on 100% hydrogen by 2025[75]. If successful, this will be world's first large scale hydrogen power retrofit. Moreover, a small ratio of hydrogen can be blended with natural gas in existing CCGTs, without complex retrofitting[17].

Main limitations of retrofits are shared by general CCS risks/barriers, however, there are special considerations specific for retrofits as well. Retrofitting only makes financial sense if plants have enough lifetime to recover their costs. Usually gas fired CCGTs have less lifetime (~25 years) than coal fired plants (~50 years), therefore the window of opportunity to retrofit CCGTs are very short compared to coal, if there is no associated life extension. However, a CCGT power plant repowered with new turbines on an existing site is a significantly cheaper option than developing a new greenfield plant, but this further option has not been considered in the scope of this study.

Furthermore, plants would have to discontinue operation, at least partially, during retrofitting and hence incur financial losses during construction. Lastly, retrofits reduce maximum power output of plants by directing some of the energy to the capture process. This may cause power security issues if there is not enough capacity in the region. Plants may alternatively build additional power generation capacity to run the capture equipment, incurring extra Capex and Opex.

Following policies, regulations and strategic decisions can be used to incentivise and enable retrofits[17,45,46]:

- Many recommendations and incentives mentioned on previous sections would help with retrofits as long as retrofitting is explicitly included or allowed in regulation.
- Countries may adopt a roadmap for transitioning from unabated fossil fuels to CCS (such as the coal phase-out programmes in some European countries) to encourage existing plants to retrofit.
- When thresholding retrofit potential of power plants, rigid criteria must be avoided and a wide set of factors must be included in analysis because some plants are likely to have a unique set of circumstances that make retrofits viable even if they appear to be unfit according to a single criterion, such as distance to storage sites.
- Retrofits may be performed at the same time as other plant upgrades, which can extend its lifetime and minimise downtime.
- New fossil fuel plants may be required to be "CCS ready" which means reserving enough space on site for a future capture facility, showing that a full chain CCS implementation would be economically feasible with a certain level of carbon cost, sufficient nearby storage capacity is accessible, routes for future T&S infrastructure can be established relatively easily, etc. These rigid criteria may be flexed by allowing plants to be CCS ready without developing a full chain model, such as allowing them to be in industrial clusters using a shared T&S infrastructure.
- Future plants can also be required to be "hydrogen ready", which involves installing state of the art gas turbines that can accept high hydrogen blends and locating themselves in proximity of potential future hydrogen production hubs.
- In regions with high governmental control over the generation fleet, initial CCS retrofit plants may be granted priority dispatch and run at higher load factors to compensate for reduced output.
- Retrofit plants may also be given a premium electricity tariff (through FiT, RAB or other mechanisms), which would be subsidised by the taxpayer or consumers.

[75] https://www.powermag.com/mhps-will-convert-dutch-ccgt-to-run-on-hydrogen/

3.3 Regional overview of current CCS support and future improvements

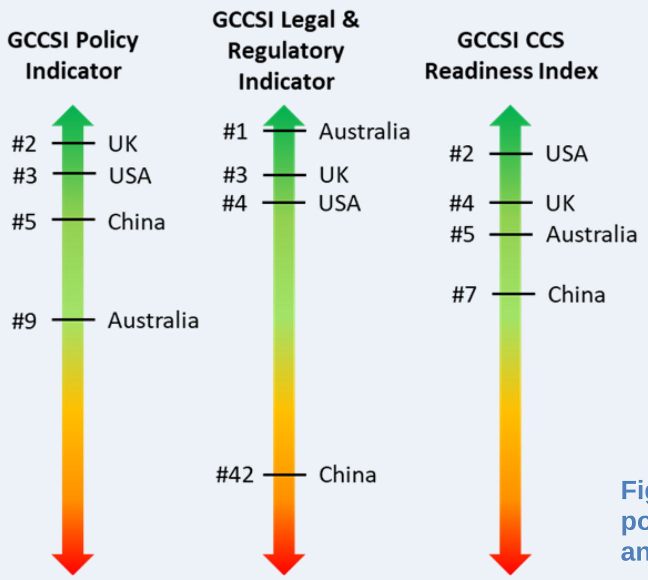
Box 3: Global CCS Institute's CCS readiness indices

GCCSI periodically determines CCS readiness of countries by tracking 3 indicators: policy, legal & regulatory and storage. Figure 31 visualises the rankings for the policy indicator, legal & regulatory indicator and overall CCS readiness index of the 4 countries studied in this report, based on the latest analysis by GCCSI in 2018. [76,77,78]

The policy indicator tracks the state of a nation's policies in their efficacy in supporting CCS deployment. The indicator is calculated by weighing 32 policy factors ranging from financial incentives to leadership and market mechanisms. The legal & regulatory indicator quantifies the completeness and efficiency of CCS regulations relating to permitting, operations, liabilities, etc. It is calculated by collating scores for 29 assessment criteria for each country. Finally, the CCS readiness index is calculated by averaging the 3 indicators (including the storage indicator, which is not presented here).

It should be noted that high rankings do not always correspond to high CCS deployment, as in the case of the UK, which has a mature regulatory regime and policies, despite lack of a large scale CCS facility. These indicators are not meant to be definitive assessments but represent one possible method to compare multiple regions in terms of their CCS progress.

The individual CCS policy and regulatory support of each country will be presented in high-level in the next sub-sections, however, a quick overview reveals that the UK, USA and China have some of the better CCS policy support, while Australia lags at rank #9. On the other hand, Australia has a relatively comprehensive regulatory regime, followed by the UK and USA. China is seriously behind other countries in terms of legal and regulatory maturity, even though it possesses many large-scale CCS projects. The strong state-sponsored nature of power companies and governmental policy support allow CCS projects to proceed without extensive regulatory regimes.



Lastly, all 4 of the studied countries rank in the top 7 in the world in overall CCS readiness, further demonstrating the real potential for all of them to deploy early CCS capacity. This also shows that each of these countries have a different approach to successfully promote CCS and it is very valuable to analyse learnings and develop recommendations for each region separately.

Figure 31: Country rankings for GCCSI's policy and legal & regulatory indicators and overall CCS readiness index

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[76] CCS Policy Indicator. GCCSI, 2018.
[77] CCS Legal & Regulatory Indicator. GCCSI, 2018.
[78] The CCS readiness index 2018: is the world ready for carbon capture and storage? GCCSI, 2018.

3.3.1 United Kingdom

Figure 32 summarises the key messages in terms of baseload, mid-merit, peaking and retrofitting CCS potential for the UK depending on the techno-economic analysis and qualitative discussion in section 2.

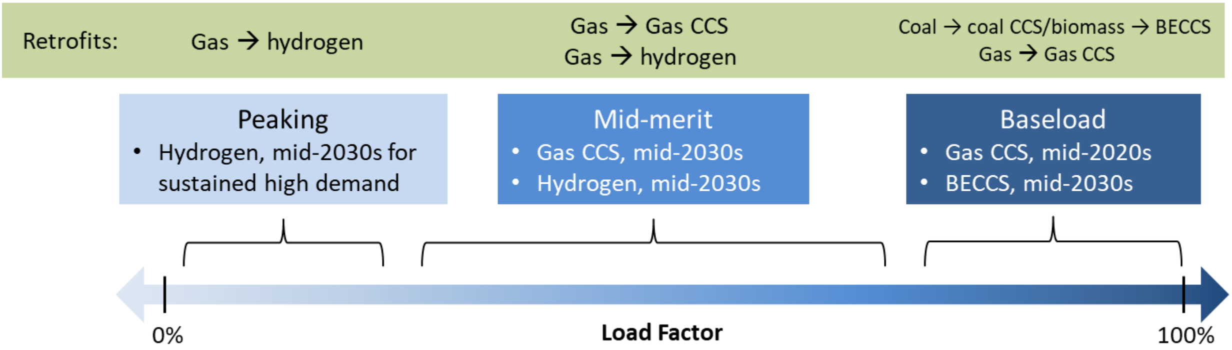

Figure 32: Summary of UK's future CCS potential

As discussed in box 3, the UK ranks highly in both the policy and legal & regulatory indicators as well as overall CCS readiness. Table 10 below lists existing and recommended policies, incentives, and actions to promote CCS in the UK.

Table 10: Current policies and regulations supporting CCS in the UK and future recommendations

	Current Support	Further Recommendations
Non-Commercial	• The UK has strong institutions- such as the CCC, BEIS, CCS Cost Challenge Taskforce, CCS Advisory Group- which drive national discourse. • The legally binding 2050 net-zero target drives research and funding into many CCS options. • "CCS readiness" regulation requires all new fossil fuel plants above 300 MW to be technically and economically ready to deploy full-chain CCS. • The UK adopted a highly developed CCS legislation going beyond the EU Directive, with extensive post-closure liability transfer provisions.	• Extend the scope of the "CCS readiness" to include hydrogen and potentially BECCS readiness. In addition, widen the definition of CCS readiness to include potential clustering, instead of deploying full chain CCS. • Encourage new power plants to be in likely future CCS cluster locations. • Limit maximum post-closure storage liability and allow companies to share storage risks with the taxpayer. • Extend all regulations and provisions to include negative emissions or at least BECCS, including developing proper MMV guidelines.
Commercial	• Despite the withdrawal of the £1 billion CCS commercialization programme, significant learnings were achieved through previous projects, which will probably reduce future project costs. • Currently the CfD mechanism is applied successfully for renewables and bioenergy. • Successful Regulated Asset Base (RAB) model applied for monopoly utilities. • The EU-ETS carbon price and national Carbon Price Floor establish a baseline for general low-carbon power support. • A new R&D grant on demonstrating negative emissions technologies is announced.	• Extend CfDs to include CCS capture businesses and BECCS. The mechanism may work on per unit of electricity generated or CO_2 captured. • Further develop and launch a flexible CfD system, or its equivalent. • Support CO_2 T&S businesses separately through a financial mechanism, potentially via RAB model. • Recognise and reward BECCS (negative emissions) in future carbon pricing or emissions schemes. BECCS can either be included in CCS incentives and/or negative emissions support.

3.3.2 United States

Figure 33 summarises the key messages in terms of baseload, mid-merit, peaking and retrofitting CCS potential for the USA depending on the techno-economic analysis and qualitative discussion in section 2.

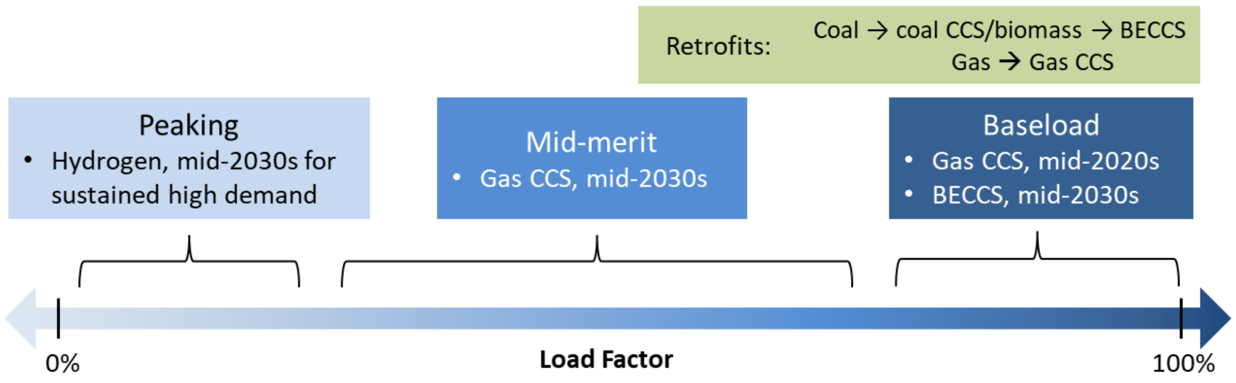

Figure 33: Summary of USA's future CCS potential

The USA, like the UK, ranks very high on all GCCSI indices. It is home to one of the two operational power CCS projects and has more projects under development. Table 11 summarises the main CCS support in the USA and suggested future actions.

Table 11: Current policies and regulations supporting CCS in the USA and future recommendations

	Current Support	Further Recommendations
Non-Commercial	• Federal level CCS regulation sets standards for permitting, well development and monitoring during operation. However, there are no provisions for transfer of liability to the government. • Some states (Montana, Texas, N. Dakota) have detailed provisions which transfer all liabilities to the state government if conditions are met after a 10-15-year period post-closure. • State level Renewable Portfolio Standards require suppliers to have a minimum amount of low-carbon electricity in their portfolio, indirectly supporting CCS among other technologies.	• Complications of projects spanning several jurisdictions arising from different underground pore space ownership rights of different states must be resolved. • Gaps in the federal CCS regime, which has a mix of different existing authorities that represent an incomplete regulatory framework, need addressing. • A form of CCS readiness requirement may be adopted to ensure that plants can be retrofitted with CCS and hydrogen in the future. • An unabated fossil fuel to CCS transition timetable can be established to foster investment into CCS retrofits. • California LCFS storage liability time period can be revised down from 100 years, to reduce liability costs.
Commercial	• Enhanced 45Q tax credits will progressively increase credit awards to \$35/tonne for EOR and \$50/tonne for dedicated storage, by 2026. Credits will be awarded for 12 years to projects that begin construction before 2024. • California Low Carbon Fuel Standard (LCFS) is amended to include CCS operations, which generate credits if used to lower fuel carbon content (by EOR). In 2019 the credits were worth \$180-\$200/tCO_2.	• Further market-based financial support, such as a CCS obligation scheme with tradable certificates (see Table 8) are necessary to promote CCS further. • 45Q tax credits almost only attract EOR projects, hence it must be improved to shift the focus on geological permanent storage.

	• 48A tax credits are available, excluding CCS, to coal projects reducing emissions through efficiency upgrades. • US DOE recently announced a $43 million R&D programme for flexible CCS. • There are several laws currently under review such as the USE IT ACT (for CCS, utilisation and negative emissions funds) and California Climate Innovation Grant Programme (voluntary tax contributions).	• Technical problems preventing coal CCS retrofits to be eligible for 48A tax credits must be resolved. • New incentives for flexible CCS operation need to be developed, which may be similar to or different than a flexible CfD. • BECCS must be included in all current and future state/federal carbon pricing schemes and support mechanisms, along with detailed MMV standards. • Deploy regulated CO_2 T&S companies.

3.3.3 China

Figure 34 summarises the key messages in terms of baseload, mid-merit, peaking and retrofitting CCS potential for China depending on the techno-economic analysis and qualitative discussion in section 2.

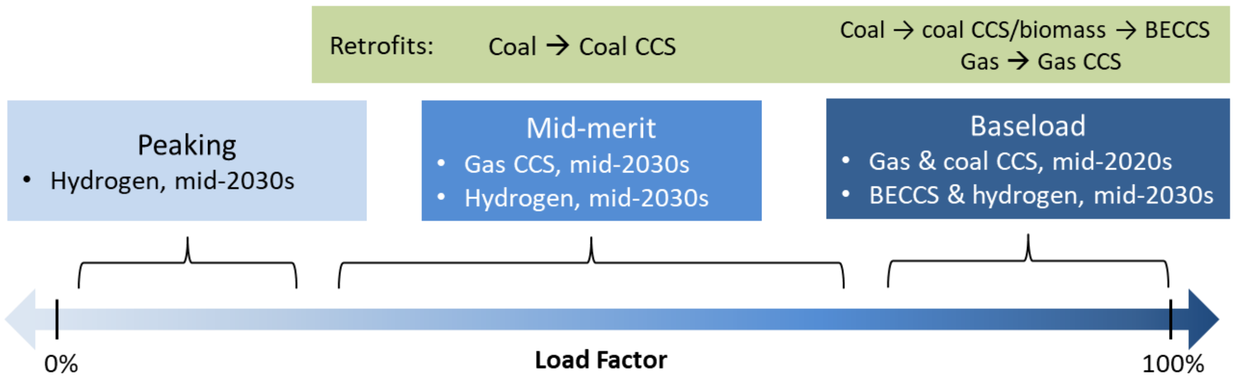

Figure 34: Summary of China's future CCS potential

China has relatively strong CCS policy support according to the GCCSI's indicators. Despite very low legal & regulatory development, China has high overall CCS readiness. Table 12 lists current CCS support mechanisms in China and future recommendations.

Table 12: Current policies and regulations supporting CCS in China and future recommendations

	Current Support	Further Recommendations
Non-Commercial	• China and Asian Development Bank announced a Roadmap for CCS Demonstration and Deployment as part of China's 13th Five Year Plan. • China consistently supports CCS R&D and demonstration through its state-sponsored activities, science and environmental ministries. • China has a national target of peaking its emissions by 2030 the latest and improving the share of non-fossil fuel energy to 20% by 2030.	• Urgently implement CCS and hydrogen readiness requirements for all new fossil fuel plants. Consider wider definitions of CCS readiness, including clustering and plant location. • Develop CO_2 storage resources further through state sponsored appraisal projects. • Develop CCS specific legal and regulatory models on par with the other regions studied in this report. • Include BECCS/negative emissions in existing and future policy. Consider coal to BECCS possibilities in national strategy. • Develop mechanisms to incentivise flexible CCS. • Publish a roadmap for unabated coal to CCS transition to allow planning for retrofitting.

Commercial	• China is planning to implement a new national carbon emissions trading system starting in 2020. • Currently Chinese renewables generators are allowed to earn a premium tariff in the wholesale electricity market. The level of support is determined by the type of technology and location[46]. • Operating hours of power plants are determined by central authorities in China. Some initial CCS demonstration plants (i.e. Haifeng in Guangdong) are allowed to operate up to 10% longer hours to recover their investment[46].	• Expand the national wholesale electricity tariffs to include CCS. It is expected that CCS tariffs would be on par with current levels of wind energy support[46]. • Develop mechanisms (as in Table 8) to incentivise CCS deployment. Public procurement may be a favourable option considering current SOE experience. • Reductions in value added tax and income tax were successfully used for renewables and may also be useful for CCS technologies[79]. • Commit to giving priority dispatch to CCS plants under China's system of centrally allocating generating hours. • Deploy state owned T&S infrastructure.

3.3.4 Australia

Figure 35 summarises the key messages in terms of baseload, mid-merit, peaking and retrofitting CCS potential for Australia depending on the techno-economic analysis and qualitative discussion in section 2.

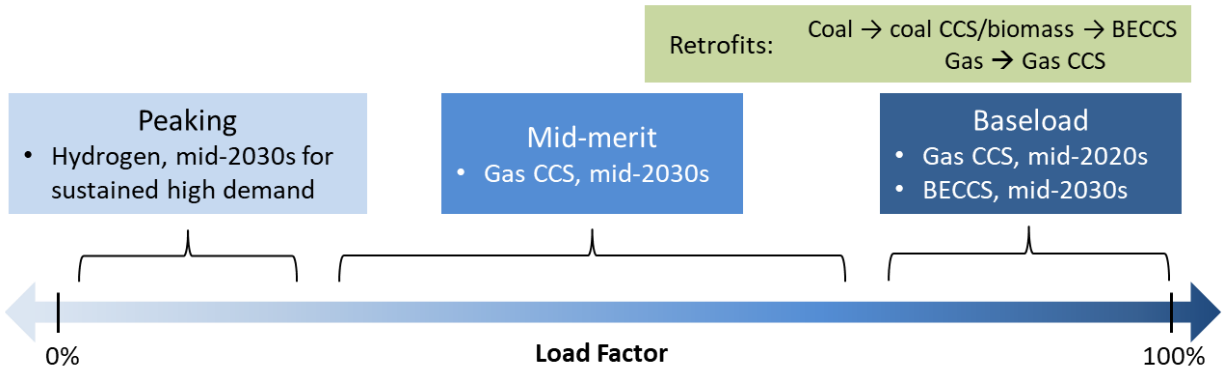

Figure 35: Summary of Australia's future CCS potential

According to the GCCSI's CCS readiness indicators Australia ranks among the top in overall CCS readiness and legal & regulatory maturity. However, it lags other countries in its policy support due to CCS being excluded from federal low-carbon power support mechanisms, adversely affecting its deployment to date. Table 3 presents an overview of current CCS related support and recommended improvement.

[79] Roadmap for carbon capture and storage demonstration and deployment in the People's Republic of China. Asian Development Bank, 2015.

Table 13: Current policies/regulations supporting CCS in Australia and future recommendations

	Current Support	Further Recommendations
Non-Commercial	• The federal government owns the offshore storage sites, enacted full primary and secondary legislation to govern injection and storage activities. • Victoria, Queensland and S. Australia also established regimes of various complexity. Western Australia adopted project-specific capture and storage regulations for the Gorgon project, the world's largest dedicated CO_2 storage project. • Australia recently published its national hydrogen roadmap, adopting an adaptive approach to hydrogen production and consumption pathways[80]. • Australia has a national target of reducing its emissions by 26-28% below 2005 levels by 2030.	• A larger national climate change mitigation roadmap and long-term targets are needed to drive smaller policies and reduce political risk. • Long-term liability and indemnification are treated differently in some states, which must be fixed. Post-closure storage liabilities may be improved. • More emphasis can be given to coal gasification and hydrogen for power in the national hydrogen roadmap. • CCS and hydrogen readiness requirements must be implemented for new plants. • Existing plants can be considered for retrofit support on a case-by-case basis. • Unabated fossil fuel to CCS transition roadmaps would be beneficial for incentivising retrofit planning. • BECCS (and other negative emissions) must be integrated into existing and future regulations along with robust MMV standards.
Commercial	• The government provided small grants to demonstration projects, undertook geological storage assessment and funded CCS R&D, which have lately stalled. • Emissions Reduction Fund includes payments via auctions for emissions cuts but most power projects, including CCS, are excluded. • Renewable Energy Target requires retailers to source a portion of their electricity from renewables. CCS is currently excluded from the mechanism.	• Expand/extend the Renewable Energy Target to include CCS or establish a similar scheme for CCS. • Expand Emissions Reduction Fund to include BECCS (considering that the fund would be limited for larger projects). • Develop and commit to national policies to contribute to Capex and Opex recovery of major CCS projects (as listed in Table 8). • Deploy regulated CO_2 T&S companies. • Support initial brown/black coal gasification projects to launch a blue hydrogen economy. Consider including H2GTs along with fuel cells in the national roadmap. • Allow Clean Energy Finance Corporation to invest in commercial CCS projects. Engage in green and sustainable bonds in the context of CCS. • Support pre-commercial demonstration projects through other mechanisms, such as grants. • Develop a policy to incentivise flexible CCS.

[80] Australia's national hydrogen strategy. COAG Energy Council, November 2019.

4. Conclusion and recommendations for further work

4.1 Key implications and conclusions

This study shows that CCS technologies have different roles from baseload to peaking operation in diverse power markets. Summaries of country specific messages are presented below, followed by key conclusions applicable across the regions.

The United Kingdom

Despite a significant share of natural gas, the UK power market is quickly phasing out coal and increasing its share of renewables with a set of policy mechanisms such as EU ETS, Carbon Price Floor, FiTs, and CfDs. The CCC net-zero report foresees a future role for BECCS, gas CCS and hydrogen for baseload, mid-merit and peaking generation, respectively.

According to our techno-economic analysis, coal CCS has virtually no role in the UK, while gas CCS plants may be viable for baseload generation from mid-2020s under the carbon price assumptions. By mid-2030s gas CCS is also a cost-effective mid-merit option along with hydrogen, which has similar costs. Hydrogen additionally has a niche role in peaking generation for providing backup during periods of high sustained demand. BECCS is very likely to have a supportive baseload role in the UK if negative emissions are rewarded similarly to the carbon cost. Lastly, unabated mid-merit and peaking plants are found to be cost effectively retrofitted by CCS or hydrogen technologies in 2030s.

The UK may unlock its CCS deployment potential through incorporating CCS into several of its existing policies, such as CfDs, RAB model for utilities and the carbon price (EU ETS or a novel mechanism in the future). Moreover, the UK would benefit from extending its existing CCS readiness regulations to hydrogen/BECCS, limiting the maximum post-closure storage liability of CO_2 storage companies and encouraging new power plants to be in clusters.

The United States

The USA is concurrently experiencing a shift from coal to gas, driven by cheap domestic shale gas availability and an increase in renewables uptake, driven by federal and state-level policies. WEO SDS expects the USA to account for 61% of global gas CCS generation by 2040 via its 94 GW capacity operating as baseload. Just under half of this capacity is expected to be retrofits.

The techno-economic analysis shows that gas CCS is likely to be the cheapest baseload technology, even in mid-2020s. BECCS is likely to be a key strategic technology for baseload generation, where the exact policy support requirement would depend on carbon accounting methodology. Low-cost domestic gas allows gas CCS to be competitive in the mid-merit role as well, starting from 2030s. Hydrogen turbines are found to be the best low-carbon option for peaking generation for sustained durations (>8 hours), but would require incentives beyond the modelled carbon price to compete with unabated CCGTs.

The USA may improve conditions for future CCS projects by establishing comprehensive CCS legal and regulatory frameworks (federal level or in each state) with compatible pore space ownership rights in neighbouring states and limiting long-term storage liability risks borne by storage companies. Furthermore, the USA may financially incentivise power CCS projects by amending the 45Q tax credits to encourage more dedicated storage rather than EOR, resolving technical issues preventing CCS projects to qualify for 48A tax credits and adopting new market-based policies, such as CCS obligations.

China

China has a very large and relatively young coal fleet supplying the country's increasing power demand, but the government is recently shifting the market to cleaner coal and renewable options for environmental reasons. According to the WEO SDS, China alone is expected to have 75% of the total global coal CCS capacity (mostly retrofits), and 20% of the total global gas CCS capacity by 2040.

Similar to the other regions, gas CCS and BECCS are viable baseline options in China from 2020s and 2030s, respectively. However, China is the only country where cheap domestic coal availability makes coal CCS a viable baseload option too from mid-2020s. Also, unlike other regions, hydrogen production costs from coal gasification are low enough in China that H2GTs are found to be economically viable for all load factors starting from 2030s, when high-efficiency 100% hydrogen turbines are expected to become available. A large portion (>300 GW) of China's coal fleet is technically retrofittable and our case study reaffirms that coal to CCS retrofits of mid-merit plants are likely to be very profitable from mid-2020s.

China traditionally has many state-owned companies in the power sector and public procurement may be an efficient method to deploy more CCS capacity and T&S infrastructure. China would also benefit from expanding current premium wholesale electricity tariffs applied to renewables to CCS and commit to granting longer running hours to CCS plants, which is currently applied to some demo plants. Lastly, China can establish a comprehensive legal and regulatory CCS framework to supplement these policies.

Australia

Despite renewables policies encouraging uptake through the Renewable Energy Target, Australia relies heavily on fossil fuel power generation. Recently, export price parity is driving domestic gas prices higher and making new gas power projects difficult to justify. Despite this, CSIRO's future power sector projections in Australia include a modest capacity of gas CCS (7-17 GW) operating at high load factors (65-82%).

This study estimates that gas CCS technology will become economically viable for baseline operations in Australia from mid-2020s and for mid-merit operations from mid-2030s. Australia is the only region studied where even the lower LCOE estimation for BECCS was higher than the unabated CCGT, therefore BECCS deployment would probably require higher incentives than the rest of the proposed CCS technologies. Likewise, hydrogen for sustained high demand is the cheapest low-carbon peaking technology, which is still more expensive than unabated gas, thus requiring additional support beyond the modelled carbon cost.

Australia may provide positive market signals for CCS projects by including CCS in its proposed post 2030 climate target, harmonising CCS regulations in different regions and capping long term storage liabilities. Furthermore, Australia may financially support new CCS projects by adopting new market-based policy mechanisms, expanding the Emissions Reduction Fund to include negative emissions technologies like BECCS and using the Clean Energy Finance Corporation to provide affordable funding for CCS. Australia could also examine a US-like approach of tax credits (45Q) to stimulate CCS.

Options for BECCS retrofits and higher capture rates

As in the case of Drax power plant in the UK, coal to biomass to BECCS conversion may be a viable niche model for long-term decarbonisation of coal dependent countries. Drax's planned BECCS conversion is partly encouraged through total phasing-out of coal generation in the UK, but similar phase-out roadmaps can be developed by other countries to signal for BECCS retrofits. Re-direction of existing biomass used for power generation to BECCS may achieve negative emissions without putting any new pressure on feedstock supply-chains.

Initial desk-based analysis indicates that increasing capture rates to >99% may eliminate residual CCS emissions cost-effectively. A recent IEAGHG study[55] found that both coal and gas CCS plants may capture all their combustion related CO_2 with a 7% increase in LCOEs compared to the 90% capture case. Our Australia based case study finds that once carbon price is considered >99% capture rate for both baseload and mid-merit coal/gas CCS plants would not have any significant impact on LCOEs compared to traditional 90% capture rates because carbon savings would cancel increased Capex and Opex costs. These findings, however, must be further confirmed by follow up studies and demonstrations.

Broader CCS Policies

Each country may choose to alleviate financial risks of CCS investments through adopting policy mechanisms that best suit their circumstances and existing regulations. All the techno-economic modelling in this study depends on ambitious carbon price projections, which represent future financial incentives for CCS technologies. High initial Capex investment and lack of a clear mechanism to generate revenues are two main barriers to CCS projects. Some options to address the Capex problem are Capex-based tax credits, direct public procurement, government grants, tax-exempt financing, accelerated depreciation, direct equity investment and cheaper financing through export credit agencies or international financing institutions. Options for ensuring revenue generation include CCS obligations or Emissions Performance Standards with tradable certificates, operational tax credits feed-in-tariffs, contract for differences and combining projects with carbon utilisation (i.e. EOR). In addition to the above policies that incentivise power plants, complimentary CO_2 T&S infrastructure must be deployed. T&S infrastructures are most likely to be shared by many capture projects and may be publicly owned or be regulated monopolies. All countries are expected to adopt some of these policies depending on their previous experience and preferences.

Apart from the generally applicable CCS policy mechanisms listed above, each country is expected to resolve challenges regarding the specific CCS applications discussed in this report:

- **Flexible Operation:** Current CCS policy mechanisms encourage maximising generation through baseload operations. Recently, a flexible CfD mechanism is proposed to incentivise running at lower load factors by providing top ups to wholesale prices only at times when unabated fossil plants are expected to run. Policies like these need to be developed further and tested adequately before being introduced widely in each region in the medium term.
- **Hydrogen:** High-efficiency and low NO_x emission 100% hydrogen turbines must be developed as soon as possible. In general, strategies involving transitioning to a wider hydrogen economy would indirectly support hydrogen for power too. Unlike other technologies, carbon capture and final energy consumption are separated in hydrogen power, so new business models and relevant support mechanisms must be developed. Governments are also encouraged to establish robust supply-chain accounting measures because tracking carbon footprints of hydrogen from multiple sources pose a serious challenge, especially for imports and exports.
- **BECCS:** In order to unlock the potential of BECCS, negative emissions need to be rewarded by inclusion in existing carbon pricing mechanisms or through dedicated new pricing systems. Furthermore, advanced measurement, monitoring and verification criteria need to be established to account for the exact level of negative emissions achieved. BECCS is also interlinked with the wider biomass and land use supply-chain therefore strict regulations are needed to ensure that feedstocks are indeed sustainable and do not cause unintentional stress on other systems, such as agriculture.
- **Retrofits:** Unabated coal and gas phase-out plans may encourage companies to start planning for retrofit options, as in the case of Drax. Meanwhile, detailed CCS/hydrogen/BECCS readiness regulations need to be established requiring all new fossil plants to be built in favourable cluster locations and have detailed plans for a future retrofit option. CCS retrofits reduce plant efficiencies and cause unit down-time during construction; therefore, governments may incentivise plants by grant support or allowing them to run at higher load factors to improve project economics, which is already being done in some demonstration plants in China.

4.2 Recommendations for further work

This study demonstrates the viability of a set of power CCS technologies to cost-effectively decarbonise baseload, mid-merit and peaking generation roles in distinct power markets. Realising this potential, however, would require urgent addressing of general, technology-specific and country-specific CCS challenges, with policy and regulatory actions that are explored in this report.

To further assess the role and value of power CCS projects, the following future work is recommended:

- Co-firing biomass in coal plants, or conversion to 100% biomass, BECCS or regular CCS could be a viable option for power markets dominated by coal. Further work on **site specific conversion of coal power plants to biomass co-firing and CCS/BECCS** would be valuable to assess specific directions these countries may go in the future.
- Although there are many studies on general post-combustion CCS technologies, **dedicated studies on BECCS and H2GTs** are limited. Therefore:
    - A dedicated BECCS study investigating the impacts of biomass supply-chain, costs and LCA emissions on future bioenergy potential; and
    - A dedicated hydrogen study investigating the interaction of hydrogen for power with other industries and the source of hydrogen, would be beneficial further work. Special emphasis should be given to hydrogen production, distribution, storage technologies and cost for end customers.
- **Expansion of the current study into other regions** with unique power markets and geographies such as India, South America, Middle East, Japan and Africa would also widen the applicability of findings and help stakeholders make better decisions tailored for their unique circumstances.
- As it was established in the report, current **specific policy mechanisms for negative emissions, flexible generation and hydrogen power generation** is very limited. Therefore, future work studying potential novel policies would help reduce this gap and allow stakeholders to implement some of the recommendations identified in this study.
- Public and political acceptability can be very influential for CCS deployment. For instance, coal CCS lost most of its political support in Europe and full-chain CCS is not likely in Germany as the public is widely against onshore CO_2 storage. Therefore, it would be instrumental to identify actions to **improve public acceptance of CCS** considering unique roles it would play in different regions.
- The economic case for CCS can be improved by coupling it with **CO_2 utilization pathways**, such as producing chemicals, synthetic fuels, using CO_2 in greenhouses, etc. Utilization pathways can provide additional grid services, like energy storage, or help decarbonise various other sectors. Efforts to determine benefits of sector coupling should employ detailed LCA methodologies which recognise the difference between dispatchable and intermittent power generation.
- Several **emerging power CCS technologies**, such as pressurized Oxy-combustion, chemical looping combustion, supercritical CO_2 power cycles (including the Allam Cycle) have potentially game changing implications. If fully realized, these technologies may reduce CCS costs significantly but also provide additional services like energy storage through cryogenic oxygen storage and enhanced grid flexibility. It would be valuable to track the development of these novel systems and study their impact on future power systems.

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6. Appendix

6.1 Appendix 1: Techno-economic data, assumptions and calculations

This Appendix lists the assumptions used for the calculation of levelized cost of electricity (LCOE) regarding technology cost and efficiency as well as regarding fuel and carbon cost. The methodology to calculate LCOE as described in the BEIS Electricity Generation Costs 2016 report has been used[81]. A discount rate of 10% has been applied for all technologies. All costs are in 2014 £.

UK technology costs

The technology cost assumptions as well as assumptions on the timing and spend profile of construction and predevelopment are listed in Table 14, Table 15, Table 16. The main sources of most cost assumptions are listed in Table 17.

FOAK/NOAK values

The data source used for CCGT CCS and H2GT specified First of a kind (FOAK) and Nth of a kind (NOAK) values. In the case of BECCS and Coal CCS, only NOAK values were specified. FOAK values were derived in these cases by assuming a 30% reduction of the premium of a CCS fitted plant compared to an unabated plant when moving from FOAK to NOAK plants. This is based on the 30% cost reduction assumption of CCGT CCS technology assumed in the data source used for CCGT CCS cost[82]. This source also assumed a 10% reduction of the efficiency penalty of CCS in a CCGT CCS plant for NOAK vs FOAK plants. We assume the same reduction holds for BECCS and Coal CCS plants.

Timelines and spend profile

Of the reviewed sources, the BEIS 2016[81] report provides the highest level of detail on construction timelines and cost profiles of CCS and non-CCS plants, therefore, it is used as the main data source in this report. (as listed in Table 14, Table 15, Table 16). The report only specifies profiles for FOAK plants. For NOAK plants we assume that the timeline of a CCS plant is the same as for an unabated plant.

Table 14: Technology cost assumptions for Coal, Coal CCS and BECCS in the UK

Technology	Coal	Coal CCS	Coal CCS	BECCS	BECCS
FOAK/NOAK	NOAK	FOAK	NOAK	FOAK	NOAK
CAPEX (£/kW)	1,563	2,302	2,080	3,462	3,078
Fixed OPEX (£/MW/year)	31,539	124,722	96,767	174,497	143,099
Var. OPEX (£/MWh)	4.42	19.25	14.80	31.47	23.12
Predevelopment (%CAPEX)	1.9%	1.6%	1.6%	2.4%	2.4%
Construction (%CAPEX)	98.1%	98.4%	98.4%	97.6%	97.6%
Reference size (net MW)	1079	785	814	389	396
Lifetime (years)	25	25	25	25	25
Efficiency (LHV)	46.0%	33.5%	34.7%	30.0%	30.6%
Capture rate	0.0%	90.0%	90.0%	90.0%	90.0%
Predevelopment (years)	3	5	3	5	2

[81] https://www.gov.uk/government/publications/beis-electricity-generation-costs-november-2016
[82] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/759538/2018_ESD_329.pdf

Construction (years)	4	5	4	5	3

Table 15: Technology cost assumption for CCGT, CCGT CCS, and H2GT in the UK

Technology	CCGT	CCGT CCS	CCGT CCS	H2GT	H2GT
FOAK/NOAK	NOAK	FOAK	NOAK	FOAK	NOAK
CAPEX (£/kW)	540	1,509	1,232	559	540
Fixed OPEX (£/MW/year)	17,584	29,792	26,503	18,079	17,584
Var. OPEX (£/MWh)	3.33	8.06	6.73	3.45	3.33
Predevelopment (%CAPEX)	1.9%	2.4%	2.4%	2.4%	1.9%
Construction (%CAPEX)	98.1%	97.6%	97.6%	97.6%	98.1%
Reference size (net MW)	1200	1056	1070	1160	1200
Lifetime (years)	25	25	25	25	25
Efficiency (LHV)	59.8%	52.6%	53.3%	57.8%	59.8%
Capture rate	0.0%	90.0%	90.0%	0.0%	0.0%
Predevelopment (years)	2	5	2	5	2
Construction (years)	3	5	3	5	3

Table 16: Technology cost assumptions for battery storage in the UK

Technology	Storage – 4h	Storage – 4h	Storage – 8h	Storage – 8h	Storage – 12h	Storage – 12h
FOAK/NOAK	FOAK	NOAK	FOAK	NOAK	FOAK	NOAK
CAPEX (£/kW)	461	324	733	514	1,004	704
Fixed OPEX (£/MW/year)	9,959	8,580	12,673	10,483	15,388	12,387
Var. OPEX (£/MWh)	0.00	0.00	0.00	0.00	0.00	0.00
Predevelopment (%CAPEX)	1.9%	1.9%	1.9%	1.9%	1.9%	1.9%
Construction (%CAPEX)	98.1%	98.1%	98.1%	98.1%	98.1%	98.1%
Reference size (net MW)	100	100	100	100	100	100
Lifetime (years)	10	10	10	10	10	10
Efficiency (LHV)	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%
Capture rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Predevelopment (years)	1	1	1	1	1	1
Construction (years)	1	1	1	1	1	1

Table 17: Sources for UK technology cost data

Technology	Detailed Technology Choice	Source
Coal	Supercritical Pulverised Coal	IEA, 2010. *Coal-Fired Power.*
Coal CCS	Supercritical Pulverised Coal with Post-Combustion Carbon Capture	Wood, 2018. *Assessing the Cost Reduction Potential and Competitiveness of Novel (Next Generation) UK Carbon Capture Technology.*
CCGT	Combined Cycle Gas Turbine	Uniper Technologies, 2018. *BEIS: CCUS TECHNICAL ADVISORY – REPORT ON ASSUMPTIONS.*
CCGT CCS	CCGT with Post-Combustion Carbon Capture	Uniper Technologies, 2018. *BEIS: CCUS TECHNICAL ADVISORY – REPORT ON ASSUMPTIONS.*
H2GT	Hydrogen-fired CCGT	Uniper Technologies, 2018. *BEIS: CCUS TECHNICAL ADVISORY – REPORT ON ASSUMPTIONS.*
BECCS	Biomass fired Circulating Fluidised Bed Boiler with Post-Combustion Carbon Capture	Wood, 2018. *Assessing the Cost Reduction Potential and Competitiveness of Novel (Next Generation) UK Carbon Capture Technology.*
Battery storage	Lithium Ion battery storage	Element Energy analysis based on: • Schmidt et al., 2017. *The future cost of electrical energy storage based on experience rates*. • Element Energy, 2019. *Batteries on wheels: the role of battery electric cars in the EU power system and beyond.*

USA technology costs

Technology cost assumptions for the US are listed in Table 18, Table 19 and Table 20. The cost assumptions for Coal, CCGT as well as Coal CCS and CCGT CCS FOAK plants are taken from the 2018 IEAGHG report *Effects of Plant Location on the Costs of CO_2 Capture* (corresponding to case 3A, IIIA, 3B, and IIIB in this report respectively). The report assumes a transport and storage cost of £8/tCO_2 (in 2014£, the value stated in the document is €10/tCO_2 in 2016€) for all countries.

The cost assumptions for Coal CCS and CCGT CCS NOAK plants have been derived by assuming a cost reduction of the premium of the CCS plant compared to the unabated plant by 30% compared to FOAK plants.

The cost of BECCS and battery storage in the US have been estimated using the IEAGHG report which investigates cost differences of unabated and CCS fitted plants between different countries.

The cost of BECCS plants have been derived from the cost assumptions on BECCS plants in the UK. For this, the ratio of BECCS costs in the US vs costs in Europe (with the UK as a representative country for Europe) is approximated by the ratio of Coal CCS plants in the US vs Europe in the IEAGHG report. The report specifies Coal CCS as well as CCGT CCS plants in various countries. The ratio of Coal CCS costs between different countries has been used rather than the ratio of CCGT CCS cost, as Coal CCS is a more CAPEX intensive technology than CCGT CCS and in that regard more similar to BECCS, which is a very CAPEX intensive technology.

Similarly, the cost of battery storage technology has been derived from the cost assumptions for the UK. For this the ratio of the cost of CCGT plants in the US vs Europe from the IEAGHG report has been used to approximate the ratio of battery storage costs in the US vs Europe (with the UK as a representative country for Europe). In this case, the ratio of CCGT costs was used for approximation, since battery storage is a technology of comparably low CAPEX intensity and among the technologies investigated in the IEAGHG report, CCGTs is the least CAPEX intensive technology.

The same timelines and spend profiles of plants have been assumed as in the UK.

Table 18: Technology cost assumptions for Coal, Coal CCS and BECCS in the US

Technology	Coal	Coal CCS	Coal CCS	BECCS	BECCS
FOAK/NOAK	NOAK	FOAK	NOAK	FOAK	NOAK
CAPEX (£/kW)	1,034	2,064	1,755	3,294	2,929
Fixed OPEX (£/MW/year)	33,209	63,081	54,119	195,230	160,102
Var. OPEX (£/MWh)	1.18	10.33	7.59	34	25
Predevelopment (%CAPEX)	1.6%	1.6%	1.6%	2.4%	1.9%
Construction (%CAPEX)	98.4%	98.4%	98.4%	97.6%	98.1%
Reference size (net MW)	999	776	806	389	396
Lifetime (years)	25	25	25	25.00	25.00
Efficiency (LHV)	42.8%	33.2%	34.5%	28.31%	28.86%
Capture rate	0.0%	90.0%	90.0%	90.0%	90.0%
Predevelopment (years)	3	5	3	5	2
Construction (years)	4	5	4	5	3

Table 19: Technology cost assumptions for CCGT, CCGT CCS and H2GT in the US

Technology	CCGT	CCGT CCS	CCGT CCS	H2GT	H2GT
FOAK/NOAK	NOAK	FOAK	NOAK	FOAK	NOAK
CAPEX (£/kW)	519	1,062	899	537	519
Fixed OPEX (£/MW/year)	15,581	29,712	25,473	16,020	15,581
Var. OPEX (£/MWh)	0.16	3.94	2.81	0.17	0.16
Predevelopment (%CAPEX)	1.9%	2.4%	2.4%	2.4%	1.9%
Construction (%CAPEX)	98.1%	97.6%	97.6%	97.6%	98.1%
Reference size (net MW)	785	696	705	759	785
Lifetime (years)	25	25	25	25	25

Efficiency (LHV)	59.6%	52.9%	53.6%	57.6%	59.6%
Capture rate	0.0%	90.6%	90.0%	0.0%	0.0%
Predevelopment (years)	2	5	2	5	2
Construction (years)	3	5	3	5	3

Table 20: Technology cost assumptions for battery storage in the US

Technology	Storage – 4h	Storage – 4h	Storage – 8h	Storage – 8h	Storage – 12h	Storage – 12h
FOAK/NOAK	FOAK	NOAK	FOAK	NOAK	FOAK	NOAK
CAPEX (£/kW)	477	334	758	531	1,038	728
Fixed OPEX (£/MW/year)	10,114	8,689	12,920	10,656	15,726	12,624
Var. OPEX (£/MWh)	0.00	0.00	0.00	0.00	0.00	0.00
Predevelopment (%CAPEX)	1.9%	1.9%	1.9%	1.9%	1.9%	1.9%
Construction (%CAPEX)	98.1%	98.1%	98.1%	98.1%	98.1%	98.1%
Reference size (net MW)	100	100	100	100	100	100
Lifetime (years)	10	10	10	10	10	10
Efficiency (LHV)	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%
Capture rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Predevelopment (years)	1	1	1	1	1	1
Construction (years)	1	1	1	1	1	1

China technology costs

Technology cost assumptions for China are listed in Table 21, Table 22, and Table 23. The cost assumptions for Coal, CCGT as well as Coal CCS and CCGT CCS FOAK plants are taken from the 2018 IEAGHG report *Effects of Plant Location on the Costs of CO_2 Capture* (corresponding to case 8A, VIIIA, 8B, and VIIIB in this report respectively). The report assumes a transport and storage cost of £8/tCO_2 (in 2014£, the value stated in the document is €10/tCO_2 in 2016€) for all countries.

The cost for Coal CCS and CCGT CCS NOAK plants and for BECCS and battery storage have been estimated using the same approach as described in the USA technology costs section.

Table 21: Technology cost assumptions for Coal, Coal CCS and BECCS in China

Technology	Coal	Coal CCS	Coal CCS	BECCS	BECCS
FOAK/NOAK	NOAK	FOAK	NOAK	FOAK	NOAK
CAPEX (£/kW)	778	1,565	1,329	2,497	2,220
Fixed OPEX (£/MW/year)	29,005	57,421	48,896	177,715	145,738
Var. OPEX (£/MWh)	0.25	8.71	6.17	28.42	20.88
Predevelopment (%CAPEX)	1.6%	1.6%	1.6%	2.4%	1.9%
Construction (%CAPEX)	98.4%	98.4%	98.4%	97.6%	98.1%
Reference size (net MW)	1016	799	808	389	396

Lifetime (years)	25	25	25	25.00	25.00
Efficiency (LHV)	43.5%	34.2%	34.6%	29.2%	29.7%
Capture rate	0.0%	90.0%	90.0%	90.0%	90.0%
Predevelopment (years)	3	5	3	5	2
Construction (years)	4	5	4	5	3

Table 22: Technology cost assumptions for CCGT, CCGT CCS and H2GT in China

Technology	CCGT	CCGT CCS	CCGT CCS	H2GT	H2GT
FOAK/NOAK	NOAK	FOAK	NOAK	FOAK	NOAK
CAPEX (£/kW)	373	739	629	386	373
Fixed OPEX (£/MW/year)	13,799	26,969	23,018	14,187	13,799
Var. OPEX (£/MWh)	0.03	3.66	2.57	0.03	0.03
Predevelopment (%CAPEX)	1.9%	2.4%	2.4%	2.4%	1.9%
Construction (%CAPEX)	98.1%	97.6%	97.6%	97.6%	98.1%
Reference size (net MW)	1,225	1,087	1,100	1,185	1,225
Lifetime (years)	25	25	25	25	25
Efficiency (LHV)	61.2%	54.3%	55.0%	59.2%	61.2%
Capture rate	0.0%	90.0%	90.0%	0.0%	0.0%
Predevelopment (years)	2	5	2	5	2
Construction (years)	3	5	3	5	3

Table 23: Technology cost assumptions for battery storage in China

Technology	Storage – 4h	Storage – 4h	Storage – 8h	Storage – 8h	Storage – 12h	Storage – 12h
FOAK/NOAK	FOAK	NOAK	FOAK	NOAK	FOAK	NOAK
CAPEX (£/kW)	342	240	544	381	745	523
Fixed OPEX (£/MW/year)	8,768	7,745	10,782	9,157	12,796	10,570
Var. OPEX (£/MWh)	0.00	0.00	0.00	0.00	0.00	0.00
Predevelopment (%CAPEX)	1.9%	1.9%	1.9%	1.9%	1.9%	1.9%
Construction (%CAPEX)	98.1%	98.1%	98.1%	98.1%	98.1%	98.1%
Reference size (net MW)	100	100	100	100	100	100
Lifetime (years)	10	10	10	10	10	10
Efficiency (LHV)	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%
Capture rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Predevelopment (years)	1	1	1	1	1	1
Construction (years)	1	1	1	1	1	1

Australia technology costs

Technology cost assumptions for China are listed in Table 21, Table 22, and Table 23. The cost assumptions for Coal, CCGT as well as Coal CCS and CCGT CCS FOAK plants are taken from the 2018 IEAGHG report *Effects of Plant Location on the Costs of CO_2 Capture* (corresponding to case 6A, VIA, 6B, and VIB in this report respectively). The report assumes a transport and storage cost of £8/tCO_2 (in 2014£, the value stated in the document is €10/tCO_2 in 2016€) for all countries.

The cost for Coal CCS and CCGT CCS NOAK plants and for BECCS and battery storage have been estimated using the same approach as described in the USA technology costs section.

Table 24: Technology cost assumptions for Coal, Coal CCS and BECCS in Australia

Technology	Coal	Coal CCS	Coal CCS	BECCS	BECCS
FOAK/NOAK	NOAK	FOAK	NOAK	FOAK	NOAK
CAPEX (£/kW)	1,481	2,822	2,420	4,504	4,005
Fixed OPEX (£/MW/year)	47,638	86,798	75,050	268,634	220,298
Var. OPEX (£/MWh)	0.83	9.55	6.94	31.16	22.89
Predevelopment (%CAPEX)	1.6%	1.6%	1.6%	2.4%	1.9%
Construction (%CAPEX)	98.4%	98.4%	98.4%	97.6%	98.1%
Reference size (net MW)	999	787	798	389	396
Lifetime (years)	25	25	25	25.00	25.00
Efficiency (LHV)	42.8%	33.7%	34.1%	28.7%	29.3%
Capture rate	0.0%	90.0%	90.0%	90.0%	90.0%
Predevelopment (years)	3	5	3	5	2
Construction (years)	4	5	4	5	3

Table 25: Technology cost assumptions for CCGT, CCGT CCS and H2GT in Australia

Technology	CCGT	CCGT CCS	CCGT CCS	H2GT	H2GT
FOAK/NOAK	NOAK	FOAK	NOAK	FOAK	NOAK
CAPEX (£/kW)	648	1,293	1,099	670	648
Fixed OPEX (£/MW/year)	20,153	38,605	33,070	20,721	20,153
Var. OPEX (£/MWh)	0.01	3.65	2.56	0.01	0.01
Predevelopment (%CAPEX)	1.9%	2.4%	2.4%	2.4%	1.9%
Construction (%CAPEX)	98.1%	97.6%	97.6%	97.6%	98.1%
Reference size (net MW)	1,210	1,072	1,085	1,171	1,210
Lifetime (years)	25	25	25	25	25
Efficiency (LHV)	61.0%	54.1%	54.8%	59.0%	61.0%
Capture rate	0.0%	90.0%	90.0%	0.0%	0.0%
Predevelopment (years)	2	5	2	5	2
Construction (years)	3	5	3	5	3

Table 26: Technology cost assumptions for battery storage in Australia

Technology	Storage – 4h	Storage – 4h	Storage – 8h	Storage – 8h	Storage – 12h	Storage – 12h
FOAK/NOAK	FOAK	NOAK	FOAK	NOAK	FOAK	NOAK
CAPEX (£/kW)	595	417	946	663	1,296	909
Fixed OPEX (£/MW/year)	11,297	9,519	14,799	11,974	18,301	14,430
Var. OPEX (£/MWh)	0.00	0.00	0.00	0.00	0.00	0.00
Predevelopment (%CAPEX)	1.9%	1.9%	1.9%	1.9%	1.9%	1.9%
Construction (%CAPEX)	98.1%	98.1%	98.1%	98.1%	98.1%	98.1%
Reference size (net MW)	100	100	100	100	100	100
Lifetime (years)	10	10	10	10	10	10
Efficiency (LHV)	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%
Capture rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Predevelopment (years)	1	1	1	1	1	1
Construction (years)	1	1	1	1	1	1

Fuel cost assumptions

Gas and coal fuel prices for the UK were taken from BEIS Fossil Fuel Price Assumptions 2018, the prices for the US, China and Australia were taken from the IEAGHG report *Effects of Plant Location on the Costs of CO_2 Capture.* The used prices are listed in Table 27. All prices are per MWh LHV and in 2014£.

Table 27: Coal and gas price assumptions

	Coal (£/MWh)	Gas (£/MWh)
UK	7.8	22.1
US	6.1	7.3
China	5.2	21.7
Australia	5.8	10.1

For the storage electricity costs, average industrial electricity prices have been collected for all countries. Due to the flexibility of storage it is assumed that the storage will charge in hours of low electricity price. Therefore, an identical reduction factor is applied to the reported average industrial electricity prices in each country. The used electricity prices are listed in Table 28. All costs are in £2014.

Table 28: Electricity price assumptions

	Electricity price (£/MWh)	Based on reference
UK	54.7	BEIS, 2019. *Quarterly Energy Prices.*
US	33.5	BEIS, 2019. *Quarterly Energy Prices.*
China	63.6	CEIC, 2019. *China Electricity Price.*
Australia	41.5	Power Technology, 2018. *Australia Energy Prices.*

To include the impact of a rising carbon price on the electricity price, the carbon intensity of electricity in the investigated countries has been taken into account. For the UK, the carbon intensity as projected by the UK government has been used (BEIS, 2019. *Green Book supplementary guidance: valuation of energy use and greenhouse gas emissions for appraisal*). For the other countries, the carbon intensity has been modelled, based on the projected electricity mix. The electricity mix in the countries is taken from the Sustainable Development Scenario of the 2018 IEA World Energy Outlook in the case of the US and China and from Scenario 3 of (CSIRO, 2017. *Low Emission Technology Roadmap*) in the case of Australia.

The biomass cost assumptions and corresponding sources are listed in Table 29. All costs are per MWh LHV and in 2014£. They are referring to wood pellet costs in the respective countries.

Table 29: Biomass cost assumptions

	Biomass cost (£/MWh)	Reference
UK	24.0	Ricardo, 2018. *Global biomass markets.*
US	19.9	Ricardo, 2018. *Global biomass markets.*
China	18.3	IEA, 2017. *Global Wood Pellet Industry and Trade Study 2017.*
Australia	19.3	TICO, 2019. *Vietnam wood pellet production and exports.*

For Australia, Vietnamese wood pellet prices as delivered to South Korea have been used as an estimate due to the following reasons. The Australian wood pellet industry is small[83] whereas Vietnam is a main exporter in the South-East-Asian market[84]. Domestic Australian wood pellets are therefore likely to have to compete with Vietnamese imports if BECCS or other bioenergy-based technologies are scaled up.

Assumed hydrogen costs and references are listed in Table 30. All costs are in £2014 and per MWh LHV. Costs in the UK are based on Autothermal Reforming of Natural Gas, an emerging technology which is being developed further by industry stakeholders and which is studied in (Element Energy, 2019, *Hydrogen production with CCS and bioenergy*). The costs in the US, China and Australia are based on (IEA, 2019, *The Future of Hydrogen*). The costs are those of the cheapest low carbon hydrogen production technology in each region according the IEA report. In the US and Australia, this is Steam Methane Reforming with CCS, in China it is coal gasification with CCS.

[83] Global Wood Pellet Industry and Trade Study 2017. IEA, 2017.
[84] Global biomass markets. Ricardo, 2018.

Table 30: Hydrogen cost assumptions

	Hydrogen cost (£/MWh)	Reference
UK	44.9	Element Energy, 2019. *Hydrogen production with CCUS and bioenergy.*
US	34.0	IEA, 2019. *The Future of Hydrogen.*
China	34.0	IEA, 2019. *The Future of Hydrogen.*
Australia	42.0	IEA, 2019. *The Future of Hydrogen.*

Carbon price assumptions

Carbon prices for the UK are based on the UK government's projection[85]. Carbon prices for the US, China and Australia are based on the carbon price projection in the Sustainable Development Scenario in the 2019 IEA World Energy Outlook. For the US and Australia, the carbon price projected for developed economies has been used, for China the carbon price projected for developing economies has been used. Prices are in £2014.

Table 31: Carbon price assumptions (£/tonne CO_2)

	UK	US	China	Australia
2025	44.3	46.4	31.9	46.4
2026	50.5	51.9	36.6	51.9
2027	56.8	57.5	41.4	57.5
2028	63.1	63.1	46.1	63.1
2029	69.3	68.6	50.9	68.6
2030	75.6	74.2	55.6	74.2
2031	82.6	77.1	59.3	77.1
2032	89.6	80.1	63.1	80.1
2033	96.7	83.1	66.8	83.1
2034	103.7	86.1	70.5	86.1
2035	110.7	89.0	74.2	89.0
2036	117.7	92.0	77.9	92.0
2037	124.8	95.0	81.6	95.0
2038	131.8	97.9	85.3	97.9

[85] Green Book supplementary guidance: valuation of energy use and greenhouse gas emissions for appraisal. BEIS, 2019.

2039	138.8	100.9	89.0	100.9
2040	145.8	103.9	92.7	103.9
2041	152.8	103.9	92.7	103.9
2042	159.9	103.9	92.7	103.9
2043	166.9	103.9	92.7	103.9
2044	173.9	103.9	92.7	103.9
2045	180.9	103.9	92.7	103.9
2046	187.9	103.9	92.7	103.9
2047	195.0	103.9	92.7	103.9
2048	202.0	103.9	92.7	103.9
2049	209.0	103.9	92.7	103.9
2050	216.0	103.9	92.7	103.9
2051	223.7	103.9	92.7	103.9
2052	231.1	103.9	92.7	103.9
2053	238.5	103.9	92.7	103.9
2054	245.9	103.9	92.7	103.9
2055	253.1	103.9	92.7	103.9
2056	260.4	103.9	92.7	103.9
2057	267.4	103.9	92.7	103.9
2058	274.2	103.9	92.7	103.9
2059	280.9	103.9	92.7	103.9

Retrofit assumptions

CCGT CCS and H_2 retrofit costs in the UK are based the report by Uniper Technologies for BEIS[86], which has also been used for the analysis of new built plants in the UK. For the analysis, the cash flow of an unabated CCGT (cost assumption from the same report) plant is compared to the cash flow of a plant installing a CCS retrofit. The figures in the text show the difference of the NPV of the retrofitted plant and the NPV of the unabated plant. A 10% discount rate is used, and a remaining lifetime of 20 years is assumed.

[86] BEIS: CCUS technical advisory – report on assumptions. Uniper Technologies, 2018.

The assumptions on coal CCS retrofit costs in China are taken from the report Reducing China's Coal Power Emissions with CCS Retrofits by IEA Clean Coal Centre[87]. Again, the cash flow of the retrofitted plant and the unabated plant are compared. In this case a remaining lifetime of 30 years is assumed, due to the longer technical lifetime and lower degradation of coal plants compared to CCGTs. A 5.52% discount rate is assumed, taken from the IEA Clean Coal Centre report, which represents typical weighted average cost of capital for a power project in China.

Assumption on higher capture rates

For the study of the impact of higher capture rates, the cost data of the recent (2019) IEAGHG report *Towards zero emissions CCUS in power plants using higher capture rates or biomass* has been used. The report, commissioned from the Australian research organisation CSIRO, specifies, for both coal and CCGT technology, CAPEX, fixed and variable OPEX of an unabated plant, a plant with CCS with a capture rate of 90% and a plant with CCS with a capture rate of 99.7% in the case of coal and 99% in the case of CCGT.

As some assumptions of the CSIRO report differ from those taken in the 2018 IEAGHG report[88], which was used in the remaining analysis of our analysis, we have not used the cost of the cost data of the CSIRO report directly. Instead the relative premium of the CCS fitted power plant with the higher capture rate, as specified in the CSIRO report, was applied to the cost data of the 2018 IEAGHG report.

Figure 27 shows the difference of the LCOE of a plant with higher capture rate to the LCOE of a plant with 90% capture rate for the case of plants commissioning in Australia in 2035.

[87] Reducing China's coal power emissions with CCUS retrofits. IEA Clean Coal Centre, 2018.
[88] Effects of Plant Location on the Costs of CO2 Capture. IEAGHG, 2018.

6.2 Appendix 2: Learnings from past successful and discontinued power CCS projects

Petra Nova- United States (Operational) [89,90,91,92,93]	
Project Characterization The Petra Nova project in Texas is the only operational large-scale power-CCS project in the US, and in fact only one out of two power-CCS projects globally. The project partners are NRG, JX Nippon and Hilcorp. The project is in operation since January 2017, and its total cost is estimated at USD 1 billion. By October 2017, the project reached the threshold of over a million tons of captured CO_2. It has a maximum capture rate of ~1.8 Mtpa CO_2. The capture plant is built on NRG's power station, and CO2 is captured via post-combustion from a 240-megawatt slipstream at the WA Parish Unit 8 (640 MW). It uses a process jointly developed by Mitsubishi Heavy Industries and the Kansai Electric Power Co., utilising a high-performance solvent to separate the CO2 from the flue gas produced by conventional coal combustion. The CO_2 is transported through a 130 km pipeline to Hilcorp's West Ranch Oil Field for enhanced oil recovery (EOR). The capture unit is a retrofit, with a separate gas-fired cogeneration unit producing steam for solvent regeneration, as well as power for the process. This means that the power plant itself is not impacted by the capture system (i.e. there is no parasitic load on the power unit itself). This is important for NRG as a merchant power producer, since it wants its power production to have 100% availability, as it cannot pass the capture costs to its customers.	**Commercial Arrangements** • NRG and JX Nippon each invested ca. USD 300 million. It benefitted from a USD 190 million grant from the Clean Coal Power Initiative (CCPI) programme from the US Department of Energy. • Japan's export credit organisation JBIC and Mizuho Bank provided USD 250 million in loans. • A critical characteristic of the project is that all key project elements are within the same economic unit, hence revenue from EOR is directly benefitting the whole chain. This is in contrast with most other CCS projects where there is a commercial arrangement between the producer and the user of the CO_2.
Key Drivers • As much as this is a CCS lighthouse project, Petra Nova is an oil production project – hence revenue from enhanced oil production is key. • Federal tax credit for CO2 injection for EOR (USD 10 per tonne when the project started) provides an additional incentive.	**Success Factors and Learnings** • The Petra Nova project has shown that a post-combustion CCS project can be made to work economically; it also clearly showed that a large CCS project can be built to schedule and to budget. • Making project economics work is critical. The Petra Nova project is the only one that has able to ensure this, largely due to the fact that all parts of the CCS chain are controlled by the same entity.

[89] Petra Nova CCUS Project in USA. Presentation by Noriali Shimokata, JX Nippon Oil & Gas Exploration Corporation, June 8, 2018.
[90] https://www.nrg.com/case-studies/petra-nova.html (accessed 05 December 2019).
[91] Lessons learned from CCS demonstration and large pilot projects. Howard Herzog, MIT Energy Initiative. May 2016.
[92] Carbon capture, utilisation, and sequestration: technology and policy status and opportunities. NARUC, 5 November 2018.
[93] Carbon capture and Sequestration (CCS) in the Unites States. Peter Folger, Congressional Research Service. 9 August 2018.

Boundary Dam Power Station- Canada (Operational) [91,92,93,94,95,96,97]

Project Characterization

The Boundary Dam project in Estevan, Saskatchewan, was the first commercial-scale power plant with CCS in the world and began operations in 2014.
SaskPower, the owner and operator of the project, retrofitted unit 3 of its Boundary Dam power station with Cansolv CO_2 capture technology. The total project cost was CAD 1.3 billion (roughly CAD 800 million for building the CCS process and the remaining CAD 500 million for retrofitting the coal-fired generating unit). Boundary Dam transports and sells most of its CO_2 for EOR, shipping 90% of the captured CO_2 via a 41-mile pipeline to the Weyburn Field in Saskatchewan. CO_2 not sold for EOR is injected and stored about 2.1 miles underground in a deep saline aquifer at a nearby Aquistore injection site. The plant has a capacity of 115 MW and a capture rate of less than 1 Mtpa CO_2. To date the project has captured 3 million tonnes of CO_2.

Commercial Arrangements

- SaskPower is a crown-owned power company, with strong steer from the provincial government
- A key enabling feature of the project is the revenue from CO_2 sold to Cenovus for injection in the Weyburn oil field.
- The project also received CAD 240 million from the Canadian Federal Government.

Key Drivers

- Canada's 2012 Environmental Protection Act and the associated 420g/kWh CO_2 emission limit for plants older than 40 years left the company with the choice of building a new gas-fired plant or retrofitting with CCS.
- Fuel price stability (of lignite) at the time of decision was seen as a hedge against much more volatile gas prices.
- Ability to continue to drive value from the existing power plant
- Sale of CO_2, sulphuric acid and fly ash to offset capture cost
- EOR revenues are the main driver for the project, which are subject to price volatility risks.

Success Factors & Key Learnings

- Willingness by the utility, backed by national emissions limitations, to build a world's first large-scale power-sector CCS project
- Strong provincial political backing, as well as financial aid from the Federal Government
- Learnings from BD 3 retrofitting have been widely publicised by the SaskPower "spin-off" International CCS Knowledge Centre. The Centre's analysis shows that based on learnings from BD3, the capital cost of similar retrofit project at the Shand power station with a 2nd generation technology could be 67% lower on a per tonne captured basis

94 Boundary Dam status update May 2019: https://www.saskpower.com/about-us/our-company/blog/bd3-status-update-may-2019 (accessed 03.07.2019)
95 An analysis of how climate policies and the threat of stranded fossil fuel assets incentivise CCS deployment. Victoria Clark, MIT. June 2015.
96 Integrated carbon capture and storage project at SaskPower's Boundary Dam power station. IEAGHG, 2015.
97 Post combustion CO2 capture retrofit of SaskPower's Shand Power Station: capital and operating cost reduction of a 2nd generation capture facility. Bruce, C. et al. Conference paper for GHGT-14, Melbourne, October 2018.

Texas Clean Energy Project (TCEP)- United States (Discontinued) [91,92,98,99,100]

Project Characterization

Another Texas-based project was TCEP, the Texas Clean Energy Project. With an expected USD 2.4 billion price tag in the beginning, TCEP was developed by Seattle-based Summit Power Group. The project consisted of an Integrated Gasification Combined Cycle (IGCC) based poly-generation plant located in Odessa, Texas.

The project was designed to capture up to 90% of the plant's emissions. TCEP's three main products were electric power (approximately 400 MW of gross output), captured CO_2 for enhanced oil recovery (EOR) (approximately 2 million tons of CO_2 annually), and urea fertilizer (averaging 800,000 tons per year). Argon and other industrial gases from the project's air separation unit (ASU) would have provided additional revenue.

The project was finally terminated in May 2016, as the US DOE pulled the federal grant funding from the project. The DOE stated that it was unconvinced that the project would proceed, as it had accumulated significant delays. In addition, the project cost had increased significantly, from USD 1.98 billion to USD 3.98 billion.

Commercial Arrangements

- Under Round 3 of the Clean Coal Power Initiative (CCPI), US DOE agreed to provide up to USD 450 million in financial assistance. Due to the expiration of unused funds provided under the Recovery Act in September 2015, the total DOE funding for the project was reduced by approximately $104 million to $346 million.
- In addition, the IRS would have brought an incentive worth USD 477 billion in investment tax credits.
- The project had signed long-term agreements to sell power, CO2 and urea.

Key Drivers

- Sales of three main types of products was going to drive project economics: power, urea and CO_2.
- Government grants were the main driver in the early development stages.

Learnings

- Getting private investors to commit was a key impediment to the project. Reported only USD 45 million worth private investment was committed to the project at the time of its termination.

[98] Audit Report, DOE-OIG-18-17. Office of Inspector General, US Department of Energy. 08 February 2018.
[99] https://www.energy.gov/fe/texas-clean-energy-project (accessed 01 July 2019).
[100] Summit Texas Clean Energy LLC, Texas Clean Energy Project (TCEP). National Energy Technology Laboratory (NETL).

Kemper County CCS Project- United States (Discontinued) [91,92,93]

Project Characterization

The project was located in Kemper County, Mississippi. The construction of the 582MW power plant started in 2010, with the aim of gasification of cheap local brown coal using proprietary gasification technology. The plant was to capture around 65% of the CO_2 content of the resulting syngas's, to ensure that the plant's emissions would correspond to those of a modern natural gas combined cycle plant per MWh. Annual capture was planned to be ca. 3 million tonnes. The captured CO_2 would then be piped to oil production sites for enhanced oil recovery operations.

Kemper was initially scheduled to be operational by 2014 at a price tag of less than $3 billion. However, after serious time and cost overruns (total cost of $7.5 billion at the time), Mississippi Power announced in June 2017 that it would abandon constructing the gasification plant and the Kemper power plant would simply run on natural gas, due to availability of cheap shale gas, and coal becoming less economically viable.

Commercial Arrangements

- Mississippi Power would sell power to the grid.
- It would also sell CO_2 for enhanced oil recovery to Denbury's EOR operations in Mississippi.
- The project received USD 270 million support from US DOE Clean Coal Power Initiative round 2.

Key Drivers

- A primary driver for the project was to develop the Southern Company's proprietary gasification technology TRIG: the company expected to gain profit by selling technology after successful demonstration at Kemper. US DOE was strongly supportive of the development.
- Expected price stability: Southern Company owned the brown coal mine right by the plant and hence knew the long-term fuel price. This was seen as a hedge against volatile natural gas prices. Also, at the time of project initiation, the shale gas boom had yet to have its full impact, which changed rapidly afterwards.

Learnings

- Main problems were technical and economic. However, the main issues were not about the CO_2 capture part of the process. Rather, unsolvable problems arose from the rapid scale-up of the TRIG gasification technology, which was untested at this scale.
- Rapid scale-up of new technology has proven very challenging. A case in point is the variations of Integrated Gasification Combined Cycle (IGCC), which have been very difficult to build in large-scale.
- Rapid change in the coal – gas price differential (due to cheaper shale gas) made wider project economics not feasible anymore.

FutureGen 2- United States (Discontinued) [91,92,93,101,102]

Project Characterization

The FutureGen 2.0 was a continuation for the first FutureGen project, based on IGCC technology, and cancelled in 2008. FutureGen 2.0 was to implement an oxy-fuel power plant with CCS in Illinois, United States. The FutureGen Alliance, cooperating with Ameren Energy Resources, was to convert one unit of Ameren's Meredosia power plant in Illinois to oxy-fuel. The carbon capture technologies were designed to capture 90% of its CO_2 emissions.

The captured CO_2 was to be transported through a 30-mile pipeline to wells where it would be injected into a geologic saline formation for permanent storage. The project was designed to capture, transport, and inject approximately 1.1 million metric tons of CO_2 annually from a 168 MW (gross) power plant. FutureGen 2.0 was awarded its Class VI CO_2 injection well permits from the US EPA in 2014.

However in 2015, US DOE announced it was pulling the Federal funds allocated for the project. The Department of Energy determined that the project was highly unlikely to meet the September 2015 deadline to spend the funds.

Commercial Arrangements

- The total project cost was estimated at USD 1.3 billion.
- In January 2014, the US Department of Energy (US DOE) announced its decision to provide up to USD 1 billion in financial assistance to the FutureGen 2.0 project.
- The project was required to spend the funds, committed under the *American Recovery and Reinvestment Act* of 2009, by 30 September 2015.

Key Drivers

- Main driver was political: FutureGen 2.0 was going to be a large-scale demonstration of oxy-fuel technology strongly backed by the US DOE, and done in collaboration with an industrial consortium composed mostly of coal mining companies (the FutureGen Alliance).

Learnings

- Large-scale demonstration programmes must account for the type of technology that is being demonstrated. If spending rules have little or no flexibility, building new technology for the first time may prove difficult within tightly set time limits.
- The procedures to gain first-of-a-kind permits (in this case EPA Class VI injection permit) can be very time-consuming.

[101] US Federal Register, Vol 79, No 14. 22 January 2014.
[102] The FutureGen carbon capture and sequestration project: a brief history and issues for Congress. Peter Folger, Congressional Research Service. Feb 2014.

Peterhead Commercialisation Programme- United Kingdom (Discontinued) [103,104,105,106]

Project Characterization

The project aims to capture ~1MT of CO_2 per annum, over a period of 15 years, from an existing 400 MW combined cycle gas turbine (CCGT) located at SSE's Peterhead Power Station in Aberdeenshire, Scotland. This would be the world's first commercial scale demonstration of post combustion CCS from a gas-fired power station. 90% of CO_2 in the flue gas will be captured by an amine technology developed by a Shell subsidiary, compressed and treated on site, transported via a short (22 km) new offshore pipeline to the existing Goldeneye pipeline, to be transported and stored in Goldeneye depleted hydrocarbon reservoir. The project aimed to complete engineering design in 2016 and commission by 2020. If needed, the Goldeneye pipeline (8-9 Mtpa) and surrounding storage sites can be used by other industrial sites for clustering. Peterhead was a finalist of the UK CCS Commercialization Programme, which aimed to give up to £1 billion grant for early CCS demonstration projects.

Commercial Arrangements

- The project aimed to receive public grants for the capital expenditure, with balance equity from Shell, the project's proponent. No debt financing was planned.
- SSE, the power plant owner would earn some money for green electricity production and then pass on to Shell.
- Shell stated that it was expecting to submit bids for CfD with a strike price in the range set out by the Commercialization Programme: £150-200/MWh.

Key Drivers

- (Shared with White Rose) The £1 billion capital grant and CfD's were the main drivers for companies. These were provided by HMG to launch a CCS industry in the UK, reduce future costs and take advantage of the UK offshore knowledge and storage potential to become a global leader in CCS.
- The specific nature of this project and its developer were unique and categorised as "the exception that proved the rule". Shell had some special drivers for the project, as it was going to be a single developer which: (1) controls the full chain assets, (2) has the competence and capacity to deliver the full chain, (3) has the financial capacity for 100% equity investment, (4) has a strategic interest to deliver CCS projects, (5) has sufficient knowledge and confidence in CO_2 storage, (6) has sufficient stature to attract wider industry participation.
- Demonstration of gas CCS projects are important because most current projects focus on coal, yet gas is expected to be the dominant fossil fuel in the future and achieve lower LCOE than coal-fired CCS.
- Further utilisation of existing offshore assets.

Learnings

- Government grants and support is a major driver, but also a risk, as its withdrawal leads to project failure.
- (Shared with White Rose) Assessment of costs and benefits of CCS against other forms of low-carbon generation suffered from like-for-like comparation, where their flexibility, potential to decarbonise heating/industry are not considered.
- (Shared with White Rose) Although many CCS risks could be insured for, CO_2 leakage risk was deemed uninsurable, as it would lead to surrender of EU ETS allowances at the future market price, which is currently unknown. Projects would have to pass the majority of storage risks to the HMG, which originally wanted the companies to bear the risks.
- Using existing T&S infrastructure can significantly reduce costs.
- Government grants are necessary for storage site appraisal and project development prior to the start of CfD contracts.
- HMG policy changes over the last 13 years has reduced the appetite of many developers and investors to engage in UK CCS project development.

[103] Overview of CCS demonstration project business models: risks and enablers on the two sides of the Atlantic. Kapetaki, Z., Scowcroft, J. (2017) *Energy Procedia*, Vol 114.
[104] Lessons learned: lessons and evidence derived from UK CCS programmes, 2008-2015. Carbon Capture and Storage Association, 29 June 2016.
[105] Peterhead CCS Project: FEED Lessons Learned Report. Shell UK Ltd, 27 January 2016.
[106] Peterhead FEED Summary Report for Full CCS Chain. Shell UK Ltd, 22 March 2016.

White Rose Commercialisation Programme- United Kingdom (Discontinued) [103,104,107,108]

Project Characterization

White Rose is an integrated full-chain CCS project comprising a new coal-fired Oxy Power Plant (OPP) and a T&S network that will transfer the carbon dioxide from the OPP by pipeline for permanent storage under the southern North Sea. The OPP is a new state-of-the-art ultra-supercritical power plant with oxyfuel technology of up to 448 MWe gross electrical output (>300 MW net) that will capture around 90% of CO_2 emissions and is also designed to have the option to co-fire biomass. ~2 Mt CO_2 per annum is expected to be captured, transported through 73 km onshore and 90 km offshore pipelines and stored permanently at the Endurance site. Plant is expected to operate at baseload but will also prove its ability for flexible operation. White Rose was a finalist of the UK CCS Commercialization Programme, which aimed to give up to £1 billion grant for early CCS demonstration projects.

Commercial Arrangements

- The project is developed by Capture Power Limited (CPL), which consists of GE, Drax and BOC. The CO_2 T&S operations are sub-contracted to National Grid Carbon Limited (NGC), which is an independent subsidiary of National Grid. NGC further sub-contracts Endurance storage site operations to Carbon Sentinel Limited (CSL).
- CPL will make revenues from electricity sales at a pre-determined CfD strike price (expected to be in the £150-200/MWh range as set out in the commercialization programme), while NGC will charge system use fees for the T&S infrastructure.
- CPL is funded 35% through base equity, 3rd party equity and government grants, and 65% through debt finance.

Key Drivers

- The oversized equipment (allowing 17 Mtpa CO_2) will be used as an anchor for a possible future cluster in Yorkshire and Humber region. Phase 2 projects are expected to drop carbon T&S costs by 60-80% and require substantially lower strike prices.
- Future T&S usage fees from other projects was the main driver for NGC.
- The project will lay the groundwork for future negative emissions through up to 10% biomass burning capability. Biomass use is also a strategic interest of Drax and may be the ultimate fate of coal power plants.
- Demonstration of the potential of power CCS through oxyfuel combustion.

Learnings

- Government grants and support is a major driver, but also a risk, as its withdrawal leads to project failure. The inconsistent nature of government support reduces trust of private investment.
- Cross-chain default is a major risk for 3rd party debt/equity financers and is likely to prevent part-chain owned private investment until CCS becomes business as usual or if risks are transferred to the public sector. Multiple storage and CO2 generation sites may alleviate this problem.
- Returns on investment for the CO_2 storage business were deemed insufficient to justify companies taking the risks in reservoir and well performance that might be taken on by investors in projects producing hydrocarbons. Hence, NGC was not able to attract storage partners.
- T&S size and capacity can be greatly increased for only a small marginal cost increase, however initial projects would produce very little CO_2 to take advantage of oversizing.
- CfD's prove to be an effective mechanism leading to securing long term power purchase agreements, which are crucial for providers of debt finance.
- If the T&S infrastructure is initially build oversized, it would reduce system costs but the first anchor project would have to ask for a higher CfD strike price to pay for it. There was no mechanism to distribute the high T&S costs between the anchor and possible future projects.

[107] White Rose Full Chain FEED Summary Report. Capture Power, March 2016.
[108] White Rose Full-chain FEED lessons learnt. Capture Power, March 2016.

ROAD (Rotterdam Capture and Storage Demonstration Project)- The Netherlands (Discontinued) [103,104,109,110,111]

Project Characterization

ROAD is developed by Maasvlakte CCS Project C.V., a joint venture of E.ON Benelux and ENGIE Energie Nederland. ROAD aims to capture CO_2 from Maasvlakte Power Plant 3 (MPP3) using post combustion capture technology with amines. The recently built coal-fired power plant has 1070 MW capacity and the capture plant will be retrofitted to process 250 MW worth portion of the flue gas. The captured CO_2 (~1.1 Mtpa) will be transported through a pipeline and injected into a depleted gas field under the North Sea. Initially a 5km onshore + 20km offshore pipeline would be build to the larger P18-4 storage site, but the project was revised to reduce expenses and aimed to use the smaller (2-4 Mt capacity) Q16-Maas site only 5 km away from the plant. All capture, transport and storage permits were acquired before freezing the project for financial reasons. ROAD briefly considered a phased approach and utilisation options to be able to attract investment. After the cancellation of ROAD in 2017, local authorities launched the Rotterdam CCUS Backbone Initiative, which will deliver a shared T&S system for potential future industrial decarbonisation operations. Some of the industries have purer streams of CO_2, reducing capture costs further.

Commercial Arrangements

- The ROAD project is co-financed by the European Commission (EC) (€180 million) within the framework of the European Energy Programme for Recovery (EEPR) and the Government of the Netherlands (€150 million). In addition, the Global CCS Institute is a knowledge sharing partner of ROAD and has given financial support of €4.1 million.
- Initial business model depended on revenue streams from European Union Allowances (EUAs) within EU ETS after the construction phase.
- After EUA prices were significantly lower than forecasted, revenue stream is changed to depend on public funding. All grants are used for construction, without obligation to operate beyond commissioning. New future grants, such as Horizon 2020 and Innovation Fund, are planned to drive the operation phase of the project forward.

Key Drivers

Regional, national and EU grants given for following reasons:

- To demonstrate the technical and economic feasibility of a large-scale, integrated CCS chain on power generation.
- Start the initial groundwork for a Rotterdam CCS hub that will decarbonise the many other industrial sites along the Rotterdam Port, a key target for Rotterdam Climate Initiative.
- Help climate targets of the Netherlands, start to decarbonise the coal industry and extend fossil fuel asset utilisation.
- Establish the Netherlands as a future CCS leader, attracting potential international clients for CO_2 storage in North Sea.
- Launch European CCS projects and programmes, such as European Energy Programme for Recovery and NER300.

Learnings

- The national government support, EU support and private investment are key enablers, but also their absence is a major risk.
- The adequate regulatory framework and efficient permitting processes of the national government, and support of the local authorities allowed ROAD to easily finalise all technical elements.
- Business models that depend on revenue streams from dynamic and uncontrollable instruments, such as the EU ETS, present a big risk.
- The guidance on EU CCS Directive implies developers to have very high financial security for a possible CO_2 leakage, which may hinder project delivery. ROAD believes that risks/liabilities for storage developers must be lower than CO_2 emitters.
- Any project receiving significant grants or CfD must get State Aid approval from the EU, which is very likely to be granted, but the process would take a long time.

[109] Update on the ROAD Project and Lessons Learnt. Read, A., et al. (2014). *Energy Procedia*, Vol 63, page 6079-6095.
[110] Highlights and lessons from the EU CCS Demonstration Project Network. Kapetaki, Z., et al. (2017). *Energy Procedia*, Vol 114, page 5562-5569.
[111] ROAD – Rotterdam Capture and Storage Demonstration Project. Andy Read. SETIS Magazine, January 2016.

6.3 Appendix 3: CCS risks/challenges and potential solutions identified in reviewed literature

Risks/Barriers	Policy suggestion, recommendation, solution
Storage liability: Long term post-closure storage liabilities are very difficult for private companies to incur, because of the uncertainty and the scale of potential leakage. No entity is willing to insure against this risk, which may outlast the traditional lifetimes of a corporate entity. Many current regulations require operators to surrender carbon credits for the amount of possible leakage in the future at the price of that time. This creates large uncertainties with regards to the size of the liability faced, as predicting future carbon prices is very difficult.	1. Partial/full transfer of post-closure liability to the government, including capping liabilities. Australia, EU and Alberta (Canada) already adopted this approach although they require a different amount of minimum time before transfer of liability. 2. Partial transfer of liability during injection to the government. 3. Government and storage site operators to pay into an independently managed fund which will cover post-closure costs and not overwhelm future taxpayers. A similar approach is taken by California Low Carbon Fuel Standard scheme. (LCFS) 4. Formation of a public T&S company 5. High level of regulations regarding site selection, monitoring and verification would front-load risks and give confidence to the government to take ownership of post-closure liabilities. 6. Establishment of a new, stand-alone body or agency that would manage the full-chain risk associated with the technology's deployment. 7. Allowing storage operators to amend T&S fees in case of leakage to share costs.
Cross-chain default risk: CCS chain needs to be developed without the guarantee that all the elements will be able to work properly. Even after the construction of the project, capture side will have the risk of T&S defaulting and T&S will have the risk of not having enough capture or demand for CO2 storage.	1. Government grants for storage appraisal may help move projects forward reducing cross-chain risk as in the case of Illinois Industrial Project, Boundary Dam and South West Hub (Australia). 2. Government grants for T&S infrastructure (which is better is oversized) helped with the cross-chain risk for capture operators giving them confidence that there will be enough T&S at low costs. 3. Vertical integration of projects. 4. Public T&S company, which may later be privatised. 5. Allowing power plants to operate flexibly if the capture/storage parts are not working.
Natural monopolies: Both transport and storage sites are likely to be natural monopolies because it would be very expensive for competing companies to provide alternative services. They may charge high costs for asset utilisation and ultimately increase the cost of capture facilities too.	1. State-owned enterprises (SEO) model would lend well with the T&S component of the CCS chain, as this tend to be a natural monopoly and the government can easily control the price this way. 2. Regulated Asset Base (RAB) model is used in the UK with natural monopolies such as the water, gas, electricity networks for many years successfully.
Storage confidence: Theoretical storage capacity should be converted to "bankable" storage, which is a prerequisite for investment into CCS. Actual injectivity and capacity may be different to what is suggested in early estimations.	1. Create a low-risk political, social and regulatory environment for CO2 storage, including frameworks to facilitate access to pore space. 2. Capital grants, subsidies, tax deductions and enhanced tax incentives for selected exploration activities. 3. Establish international standards for storage characterization and auditing T&S systems. 4. Start including storage site pressure management strategies in assessment models. Late storage projects in saline aquifers may require managing waste brine production.

Risks/Barriers	Policy suggestion, recommendation, solution
Independent development timelines: So far it is assumed that the capture and T&S parts of CCS can be developed simultaneously. However, if power station build is dependent on availability of storage, appraisal would need to happen first, prolonging project times. These aspects of CCS usually have different investment timelines, which is a major risk.	1. Dependency between storage appraisal and capture facility can be eliminated if there is a national/regional CO2 T&S infrastructure already in place. The government may undertake early storage appraisal work too. 2. Government incentives for establishing CCS hubs/cluster also alleviate this risk.
Low carbon price: Current carbon prices are too low to encourage CCS investment. Future high cost are too distant and uncertain to encourage investment.	1. Governments may commit to a more ambitious carbon price ramp up rate and clearly lay out the pathway to reach there in the future. 2. A carbon floor price can establish a minimum and alleviate the effects of low carbon certificate prices due to abundance of allowances.
Knowledge spillover: Both capture and storage elements are subject to knowledge spillovers, where the initial projects generate knowledge for free for late developers. However, these newer projects would be more economically competitive and older assets may be stranded. This encourages a wait and see approach.	1. Regulated Asset Based Model (RAB) would ensure a steady return on investment and transfer cost risks to the customer, encouraging early investment. 2. Initially government owned T&S infrastructure may later be privatised when risks are reduced. This is used in several other industries like power and transport.
Cheaper carbon abatement options: Currently renewables provide a cheaper decarbonisation option in terms of cost per avoided carbon.	1. Focus on policies other than a plain carbon cost, as this would encourage just more renewables. Options include public procurement, tax credits, CCS obligation with certificates and emissions trading schemes.
Policy and revenue: Dependence of revenue and profitability on government policies present a risk since these can be changed easily over time. Tax credits are especially vulnerable of this risk.	1. This risk will exist until CCS reaches full maturity; however, governments may generate trust and reduce risks by committing to long term targets and policies and share their powers with other public institutions for decision making.
Reputational risk: Support for CCS initiatives carries political and reputational risk due to recent failures, such as the UK CCS competition, NER300, or those which have exceeded timelines and budgets e.g. Kemper county. This has resulted in the view that CCS projects are complex and vulnerable to cost over-runs.	1. Government grants for T&S infrastructure (especially oversized) would send a signal that the government is willing to support CCS in the long term.
Lack of a learning curve: CCS did not demonstrate a learning curve so far, like the renewable energy did and battery storage technologies are currently doing.	1. Special emphasis must be paid for supporting a scale-up phase, which may involve different policies than roll-out phase, such as more government procurement. 2. Continue sharing practical information on operating and discontinued projects to facilitate learning-by-doing.

Risks/Barriers	Policy suggestion, recommendation, solution
<u>Information failure:</u> Although elements of the CCS supply chain have been demonstrated, the existing scale is too small compared to other mature industries and there is a lack of operational data, leading insurance companies to put a high risk premium on finance.	1. Continue sharing practical information on operating and discontinued projects to facilitate learning-by-doing. 2. Create a central CCS organization which will coordinate all activities and work closely with the government, companies and regulators. Information from each project can then be retained in this organization to support learning by doing.
<u>Limited workforce:</u> Availability of petroleum engineers for the whole CCS supply chain and geo-engineers and drilling rigs for the storage part may present practical risks if CCS is deployed at large scales in the future. The competition between CCS and oil and gas industry may present a risk for experienced staff and drilling equipment necessary for exploration.	1. The oil and gas industry is already experienced in these storage appraisal operations and will be able to train more qualified staff in the future. 2. In the short-term, this is not expected to be a barrier since recently low oil and gas prices have resulted in a number of job losses and currently there is no shortage of skilled labour in the area.
<u>Public acceptance:</u> Success of many new technologies require wide public support. Studies show that generally public underestimates the emission cuts needed to mitigate climate change and overestimate the role of renewables. Risk perception focuses on sustainability of CCS, leakages and over pressurization of the storage sites. A further concern is reduction in renewables support in favour of CCS.	1. Closer collaboration between experts from engineering and communications in order to inform the public. 2. Transferring post-closure liabilities to the government may help with public perception since the storage sites will be controlled by an entity perceived to watch out for the public interest.

6.4 Appendix 4: List of stakeholders engaged and external reviewers

Table 32: List of stakeholders engaged in this study

Organization	Name / Surname	Title
Asian Development Bank	Darshak Mehta	CCS Technology Expert and Co-ordinator
UK Department for Business Energy and Industrial Strategy- BEIS	Jonathan Baker-Brian	Senior Policy Advisor
	Luke Jones	CCUS Policy Advisor
Drax Group	Karl Smyth	Group Head of Policy and Government Relations
US Department of Energy- DOE	Stephanie Hutson	International Activities Program Officer- Office of Fossil Energy
	Sarah Forbes	Scientist- Office of Fossil Energy
	Lynn Brickett	Carbon Capture Technology Manager
Geoscience Australia	Andrew Feitz	Section Leader, Low Carbon Geoscience and Advice
	Eric Tenthorey	Senior Researcher at CO2CRC
International Energy Association- IEA	Samantha McCulloch	Head of CCUS
	Raimund Malischek	Energy Analyst
Global CCS Institute- GCCSI	Dominic Rassool	Senior Finance & Policy Consultant

Table 33: External reviewers of the draft report

Organization	Name / Surname
The Commonwealth Scientific and Industrial Research Organisation- CSIRO	Paul Feron
UK Department for Business Energy and Industrial Strategy- BEIS	Nick Bevan
Wood	Suzanne Ferguson
Minerals Council of Australia- MCA	Peter Morris
	Josh Cosgrave
Electric Power Research Institute- EPRI	Joe Swisher
	George Booras
International Energy Association- IEA	Samantha McCulloch
	Raimund Malischek
RWE	Karl-Josef Wolf

Evaluating technology options to mitigate greenhouse gas emissions

IEA Greenhouse Gas R&D Programme

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