Technology Collaboration Programme by iea

IEAGHG

Power CCS: Potential for cost reductions and improvements

Technical Report 2024-04
July 2024

IEA Greenhouse Gas R&D Programme

About the IEA Greenhouse Gas R&D Programme

Leading the way to net zero with advanced CCS research. IEAGHG are at the forefront of cutting-edge carbon, capture and storage (CCS) research. We advance technology that reduces carbon emissions and accelerates the deployment of CCS projects by improving processes, reducing costs, and overcoming barriers. Our authoritative research is peer-reviewed and widely used by governments and industry worldwide. As CCS technology specialists, we regularly input to organisations such as the IPCC and UNFCCC, contributing to the global net-zero transition.

About the International Energy Agency

The International Energy Agency (IEA), an autonomous agency, was established in November 1974. Its primary mandate is twofold: to promote energy security amongst its member countries through collective response to physical disruptions in oil supply, and provide authoritative research and analysis on ways to ensure reliable, affordable and clean energy. The IEA created Technology Collaboration Programmes (TCPs) to further facilitate international collaboration on energy related topics.

CONTACT DETAILS

Tel: +44 (0)1242 802911
E-mail: mail@ieaghg.org
Internet: www.ieaghg.org

Address: IEAGHG, Pure Offices,
Cheltenham Office Park, Hatherley Lane,
Cheltenham, GL51 6SH, UK

Citation

The report should be cited in literature as follows: **IEAGHG, 'Power CCS: Potential for cost reductions and improvements', 2024-04, July 2024, doi.org/10.62849/2024-04.**

Acknowledgements

This report describes work undertaken by Element Energy (now ERM) on behalf of IEAGHG. The principal researchers were:

- Ignacio Rabsiun Aramburu
- Freddie Barnes
- Alexander Fish
- Michael Joos
- Foaad Tahir

To ensure the quality and technical integrity of the research undertaken by IEAGHG each study is managed by an appointed IEAGHG manager. The report is also reviewed by a panel of independent technical experts before its release.

The IEAGHG manager for this report was: Keith Burnard

The expert reviewers for this report were:

- Richard Esposito, *Southern Company*
- Nathan Bongers and Damian Dwyer, *Low Emission Technology Australia*
- Suzanne Ferguson, *Wood*
- Treasure Udabor (and colleagues), *UK DESNZ*
- Tilman Bechthold, *RWE*

POWER CCS:
POTENTIAL FOR COST REDUCTIONS AND IMPROVEMENTS

This study, undertaken on behalf of IEAGHG by ERM, explores the potential to reduce the cost and accelerate the uptake of power CCS technologies (or, more simply, "power CCS"[1]). Given the widely adopted global mission to achieve net-zero energy-related CO_2 emissions, CCS will be essential to reducing emissions in the power sector (via power CCS technologies). The findings from the study will be of interest to the broader energy community but, in particular, should benefit project developers, the finance community and policymakers.

Key Messages

- Many major economies and international organisations have committed to achieving net-zero greenhouse gas emissions by mid-century. In the transition to net-zero, reducing CO_2 emissions in the power sector will be important, with CCS (via power CCS) playing an essential role in driving down emissions from the traditional generators that employ coal and gas. Apart from reaching net-zero[2] emissions from a power CCS plant, the technology also needs to be capable of operating flexibly and be cost competitive.

- Although only four thermal power plants – Boundary Dam (Canada), Petra Nova (United States), Jinjie (China) and Taizhou (China) – have so far deployed CO_2 capture commercially at scale, multiple other thermal power plants have trialled capture technologies with smaller slipstreams and several projects are in the pipeline for construction. With several technology options under development to decarbonise thermal power generation, lessons learned from the deployment of CO_2 capture at Boundary Dam, Petra Nova, Jinjie, Taizhou and numerous pilots have already led to the identification of cost reduction opportunities.

- As the increasing penetration of intermittent renewable technologies will lead to reduced output from the more traditional generators, continuing to drive down the CAPEX and OPEX of capture processes will be essential to their provision of electricity at a competitive cost. Further cost reductions must be pursued – from the host plant, from the capture process and, of course, from their joint operation.

- The primary objective of this study was to explore the potential to improve and to further reduce the costs of CO_2 capture. Various drivers and levers including operational aspects, technological developments (in pre-, oxy- and post-combustion capture technologies) and design modifications (e.g., traditional onsite construction vs. modularisation to enable mass-production) were considered.

- As the UK had declared the goal of largely decarbonising its power system by 2035, the country's power grid was used as a case study to explore the role of power CCS in a future decarbonised power system. Several potential generation mixes of a largely decarbonised power system in the UK in 2035 were modelled.
    - A system with a high penetration of variable renewable energy (VRE) technologies was shown to have a similar or even slightly lower generation cost than a system based on dispatchable, low-carbon generation technologies only.

[1] The term "power CCS" refers to any form of thermal electricity generation that deploys carbon capture and storage (CCS).

[2] Net-zero emissions from a power CCS technology are achieved when the concentration of CO_2 emitted to the atmosphere is no higher than the concentration of CO_2 in the incoming combustion air, i.e., all fuel-derived CO_2 is captured.

- Pre-combustion CO_2 capture in the form of blue[3] hydrogen combined cycle gas turbine technology[4] (blue H2CC) was shown to be the most economic power CCS technology due to its lower CAPEX[5] compared to post-combustion capture plants.
- Whether or not VRE technologies were present on the grid, power CCS was found to be a cost-effective technology providing flexible, low carbon, dispatchable power generation.
- In a cost-efficient system based on dispatchable generation, nuclear[6] power was a key technology, operating at load factors above 85%.
- Dispatchable generation capacity was identified as an important enabler to achieve high VRE penetration while ensuring security of supply.[7] While the dispatchable generation capacity would have a lower expected load factor than in a system with no VRE generation, there may well be circumstances, from a carbon perspective or from the perspective of grid stability, where it may be more effective not to shut the plant down nor to turn it down to a level where the overall system becomes less efficient.
- The average load factor of the dispatchable fleet (i.e., comprising natural gas combined cycle[8] (NGCC) technology with post-combustion capture, blue H2CC and nuclear) in a system with high VRE penetration was less than 15%. The sum of dispatchable generation and VRE generation in such a system was more than twice the capacity in a system with no VRE technologies.
- A significant requirement for dispatchable generation remained even when batteries were deployed as flexible generation options.

Background to the Study

Many major economies and international organisations have committed to bring their greenhouse gas emissions to net zero by mid-century or earlier. In the transition to net zero, CCS will have an important role, offering a unique decarbonisation approach not only in reducing emissions from 'hard-to-abate'

[3] While colour coding offers a simple and widely used means of categorising the different methods of hydrogen production, there are no agreed definitions for the different colours, and they can obscure many different levels of potential emissions. The IEA makes a persuasive case for a clearer terminology, noting, for example, that for so-called "blue" hydrogen produced using natural gas with CCUS, analysis shows that emissions per kg of hydrogen produced can vary substantially depending on the technology used and the capture rate. In its report that reviews ways to use the emissions intensity of hydrogen production to inform an international emissions accounting framework, the IEA contends that the lack of standard terminology to describe low-emission hydrogen is a barrier to investment and scale-up and, furthermore, hinders compliance with regulatory and market requirements. In the present case, however, as the authors of the IEAGHG study used colour coding, this means of categorisation has been retained for the purposes of reporting in this Overview.

[4] Blue hydrogen = Low-carbon hydrogen derived from natural gas that is split into hydrogen and CO_2 either by steam methane reforming (SMR) or auto thermal reforming (ATR), where the CO_2 is captured and stored.

[5] Note that the CAPEX for the H2CC configuration does not include capital costs for hydrogen generation; the hydrogen is assumed to be delivered over the fence.

[6] While the authors of this report include nuclear technology within the mix of '**dispatchable**' technologies, nuclear is more often referred to as a '**firm**' technology, i.e., it can be called upon by the grid on demand. The term 'dispatchable' technology is more often reserved for technologies that can equally guarantee availability to the grid but can also ramp up and down quickly, e.g., they are able to rapidly respond to changing energy demands, often within minutes or, in some cases, seconds. Nuclear plant can, to a limited extent, respond to demand by slowly ramping its load up and down. However, it may be described as a dispatchable technology, e.g., if deployed in combination with battery energy storage.

[7] This was also a finding in an earlier IEAGHG study: 'IEAGHG, "Valuing Flexibility in CCS Power Plants", 2017/09, November 2017'.

[8] NGCC technology is also commonly termed combined cycle gas turbine (CCGT) technology.

sectors such as steel, cement and lime, but also in reducing emissions in the power sector (via power CCS).

Several technology options are under development to decarbonise thermal power generation. While only four thermal power plants – Boundary Dam (Canada), Petra Nova (United States), Jinjie (China) and Taizhou (China) – have commercially deployed CO_2 capture at large scale[9], multiple other thermal power plants have trialled capture technologies with smaller slipstreams and several projects are in the pipeline for construction.[10] Lessons learned from the deployment of CO_2 capture at the commercial-scale plants and numerous pilots have already led to the identification of cost reduction opportunities.

While it has been shown possible to reach net-zero emissions from a power generation plant with CO_2 capture,[11] the plant would also need to be capable of operating flexibly and be cost competitive. To provide electricity from power CCS technologies at a competitive cost, it is essential that CAPEX and OPEX continue to be driven down. The potential for further cost reductions must be pursued – from the host plant, from the capture process and, of course, from their joint operation. For example, for an NGCC unit with capture, equipment associated with the NGCC will have been developed over many years and will already have progressed some way down the cost curve. It remains to explore what technology development and/or operational enhancements would further reduce costs.

As well as technological improvements and/or operational enhancements, design modifications may also lead to cost savings. For example, within the CCS supply chain, the cost of traditional onsite construction is being compared with "modular" construction for the early capture projects.

Moreover, a power plant with CO_2 capture will perform differently to that same power plant without capture, e.g., regarding ancillary services to the grid. The capture system requires power and this may impact the plant's start-up times and ramp rates and, consequently, its value to the grid may be affected[12]. These factors need to be explored, with cost and performance compared with those of competing technologies such as wind with battery storage.

The increasing penetration of intermittent renewable technologies will lead to reduced output from the more traditional generators. While this will result in occasions where a plant with CO_2 capture may periodically be shut down, there may well be circumstances, from a carbon perspective or from the perspective of grid stability, where it may be more effective not to shut the plant down nor to turn it down to a level where the system becomes less efficient.

Scope of Work

The primary objective of this study was to explore the potential to further reduce the costs of CO_2 capture and make the technology a more competitive low-carbon option. CO_2 capture costs from previous studies were assessed, with insights integrated into a techno-economic analysis of power CCS and other power generation options that enabled the role that power CCS technologies could play in the generation mix of a largely decarbonised power system to be explored. CO_2 capture[13] is widely seen as an essential tool for decarbonising the use of natural gas and coal in the power sector. The analysis sought to identify areas where cost reductions might be achieved. Various drivers and levers were considered, including operational aspects, technological developments (including pre-, oxy- and post-

[9] With the plants capturing from 150 000 t CO_2/a to well over 1 Mt CO_2/a.
[10] Global CCS Institute, "The Global Status of CCS 2023", November 2023. Australia.
[11] IEAGHG, "Towards zero emissions CCS from power stations using higher capture rates or biomass", 2019/02, March 2019.
[12] IEAGHG, "Beyond LCOE: Value of technologies in different generation and grid scenarios", 2020-11, September 2020.
[13] In the near- to medium-term, growth in the sector is expected to be led by post-combustion amine-based absorption capture technologies.

combustion capture technologies) and design modifications (e.g., traditional onsite construction vs. modularisation) to enable mass-production.

The techno-economic analysis was undertaken to explore the potential competitiveness of power CCS compared to alternative flexible power generation options, e.g., VRE technologies (solar/wind) with battery storage. The relative competitiveness of natural gas pre-combustion CCS (blue hydrogen-fired combined cycle gas turbines) versus post-combustion CCS as a function of the utilisation of the plants was also investigated.

To underpin the techno-economic analysis, several potential generation mixes of a largely decarbonised power system in the UK in 2035 were investigated – noting that the UK has declared the goal of largely decarbonising its power system by 2035 – and the role that power CCS technology could play established. The generation mixes were based on dispatchable generation technologies, including nuclear and power CCS, as well as on VRE technologies, with their total annual costs compared. Of particular interest, the capacity and utilisation of power CCS technologies deployed in these different versions of a future UK power system were determined.

Findings of the Study

While, in the longer term, many capture technologies mentioned in this report could potentially demonstrate merits to capture a significant share of power CCS deployment, only options with a high near- and medium-term potential (i.e., before the mid-2030s) were included in the techno-economic assessment. Post-combustion is the primary method proposed currently for use in existing power plants, with amine-based absorption being the most mature technology. having been used, e.g., in Boundary Dam and Petra Nova. Oxy-fired supercritical power generation, based on the Allam cycle, was also taken forward to the techno-economic assessment, with a utility-scale project planned to be in operation in the late 2020s.[14] The techno-economic assessment thus includes:

- NGCC power plant with post-combustion capture
- Super critical pulverised coal (SCPC) power plant with post-combustion capture
- Oxy-fired supercritical power generation (Allam cycle)[15]

Capture rates substantially higher than 90% have been shown to be achievable[16] and have a modest impact on costs compared to the cost of achieving 90%. However, as 90% capture rate has been the baseline target for most studies to date, applying this value offers good potential for model validation and, purely for this reason, 90% was used as the base case for the techno-economic model used in this study. Capture rates higher than 95% were also modelled to represent the evolving drive towards higher capture rates.

Cost estimates for power CCS were built on multiple publicly available bottom-up cost models. Three main sources of bottom-up data were identified through the literature review: Wood's report for BEIS in 2018 on next generation capture technologies,[17] IEAGHG's benchmarks from 2020,[18] and the U.S. Department of Energy's National Energy Technology Laboratory (NETL) Cost and Performance Baseline for Fossil Energy Plants.[19] Cost metrics as shown in Table 1 were derived from these reports and taken forward to the techno-economic assessment.

[14] See https://netpower.com/first-utility-scale-project.
[15] The Allam cycle has a lower TRL than the other capture methods.
[16] IEAGHG (2019) Towards zero emissions CCS with biomass or higher capture rates.
[17] Assessing the Cost Reduction Potential and Competitiveness of Novel (next Generation) UK Carbon Capture Technology, Wood, October 2018.
[18] IEAGHG, "Update techno-economic benchmarks for fossil fuel-fired power plants with CO_2 capture", 2020/07, July 2020.
[19] Cost and Performance Baseline for Fossil Energy Plants Volume 1, Revision 4, US Department of Energy. September 2019.

Multiple cost reduction opportunities were identified and prioritised, some applying to CAPEX and others to OPEX. CAPEX reductions are particularly important for cost-effective power CCS facilities, as it is anticipated that future operation may well be at low load factors to support the higher penetration of variable renewable energy.

Table 1: Cost metrics for power CCS technologies

Technology	Reference	CAPEX (£/kW)	Fixed OPEX (£/kW/y)	Variable OPEX[20] (£/MWh)	Net power output (MW)	Fuel efficiency (LHV)	Capture rate	Share of biomass (% of energy input)
NGCC w/o PCC	IEAGHG benchmarks	746	21	0.5	1,506	59.0%	-	0%
SCPC w/o PCC	NETL	2,037	56	6.1	650	41.6%	-	0%
NGCC w/ PCC	IEAGHG benchmarks	1,470	41	1.1	1,344	52.7%	90%	0%
SCPC w/ PCC	NETL	3,668	95	11.0	650	32.5%	90%	0%
SCPC w/ PCC + biomass co-firing	NETL	3,834	98	11.2	650	31.8%	90%	8.1%
BECCS	BEIS	3,392	158	28.3	396	30.6%	90%	100%
Allam cycle	BEIS	1,541	70	7.0	848	52.3%	90% [21]	0%
SCPC w/ PCC 99%	NETL	3,844	99	11.8	650	30.9%	99%	0%
NGCC w/ PCC 98.5%	IEAGHG benchmarks	1,583	44	1.2	1,316	51.6%	98.5%	0%

At low load factors, **CAPEX** is spread across a reduced number of operating hours, and hence the CAPEX share of LCOE[22] increases. Measures that target reductions in CAPEX are therefore important to improve the economics of future CCS installations deployed in the power sector. Among the different CAPEX reduction opportunities, priority areas for action were identified as:

- Scale-up of the CO_2 capture plant
- Site layout and modularisation
- Development of a CCS supply chain
- Flue gas recirculation,[23] and
- Capture plant de-risking.

[20] Note: Variable OPEX does not include fuel costs.
[21] The Allam cycle can achieve capture rates over 95%. The 90% figure reflects the age of the study and is not linked to the technical potential to achieve very high capture rates.
[22] Historically, the levelised cost of electricity (or LCOE) has been the metric most commonly used for evaluating different generation technologies – and is still used by many in the modelling community. While it remains a useful metric for comparing the relative merits of generation technologies that offer the same services, as the generation mix diversifies, LCOE becomes less useful. To address this failing, several LCOE variants have been proposed, including the IEA's VALCOE (Value-Adjusted Levelized Cost of Electricity) to better reflect the true costs and benefits of different generation technologies. VALCOE considers not just LCOE but also the value of energy, capacity, and flexibility values of generation technology. Notably, for CCS-equipped plants, VALCOE can be significantly lower than LCOE.
[23] Flue gas recirculation also brings significant OPEX reduction opportunities.

OPEX also contributes significantly towards the overall cost of a CCS facility. Most of this is related to the thermal energy and steam generation requirements to separate the CO_2 from the flue gases (in the case of post-combustion) or the waste gases (in the case of pre-combustion or oxy-fuel approaches). The most important action areas for OPEX reduction opportunities were identified as:

- Lowering amine degradation
- Maintenance costs, and
- Optimisation of heat integration.

The **techno-economic analysis** undertaken explored power CCS and its potential competitiveness compared to alternative flexible power generation options to back up VRE technologies (solar/wind). Such options include battery energy storage, which can compete with dispatchable generation at low load factors. Furthermore, the relative competitiveness was investigated of natural gas **pre-combustion capture**, i.e., blue H2CC,[24] versus NGCC technology with **post-combustion capture** (NGCC w/ PCC) as a function of the utilisation of the plants. The cost estimates, shown in Figures 1a and 1b, consider the impact of any learnings from power CCS demonstration projects as assessed in the first part of the study. Based on the assumptions used in this study, in 2035, due to their lower CAPEX requirements,[25] blue H2CCs were shown to be more cost efficient than NGCCs w/ PCC below load factors of 50%.[26] NGCCs w/ PCC on the other hand were more cost competitive than nuclear generation at load factors below 90%.

Finally, several potential generation mixes of a largely decarbonised power system in **the UK in 2035** were investigated, exploring the role that power CCS technology could play. This built on the techno-economic analysis described above by deploying generation technologies in a cost-optimal way given different constraints. Power generation mixes based on dispatchable generation technologies including nuclear and power CCS were investigated, as well as mixes based predominantly on variable renewable energy, and their total annual costs compared. A key focus of the analysis was the optimal deployed capacity of power CCS technologies in these different versions of a future UK power system and their utilisation. The study assumed a significant increase of electricity demand in the UK in 2035, driven by electrification in heat, transport, and industry, leading to a peak demand of 82 GW compared to 54 GW today (i.e., a 52% increase). In both systems, power CCS technologies provided flexibility to the power grid system in the form of low-carbon, dispatchable power generation. Three cost-optimal scenarios were presented:

- Scenario **Dispatchable** presents an optimised mix of low-carbon, dispatchable technologies with no renewables
- Scenario **VRE** presents a mix with high renewable penetration and a cost-optimal dispatchable fleet
- Scenario **VRE + storage** presents a mix with high renewable penetration, battery energy storage, H_2 power to power storage, and a cost-optimal dispatchable fleet

[24] This assumes a separate blue hydrogen plant and hydrogen gas turbine – it does not reflect costs for an Integrated Gasification Combined Cycle (IGCC).
[25] The cost of H_2 gas turbines is equated with NGCCs based on promising results from examples of H_2 mixing in NGCCs. However, no techno-economic data exists validated by real tests of 100% H2GT and regulative questions remain unanswered (for example NOx formation and the cost of deNOx systems).
[26] The modelling assumes blue H_2 supply exactly meets H_2 demand meaning that the requirement for blue H_2 is determined by the load factor.

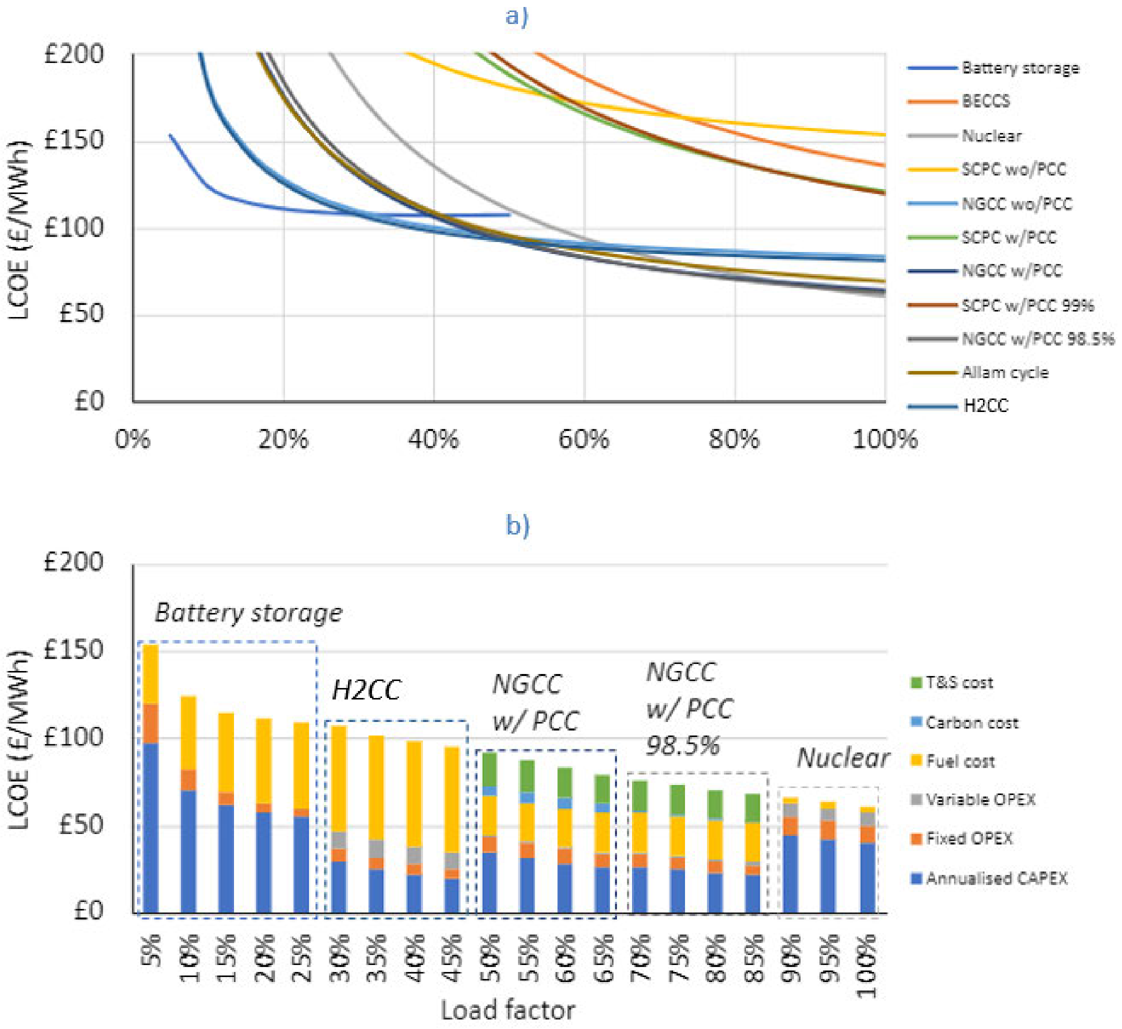


Figure 1a: LCOE for various power generation technologies and **1b:** Best LCOE with an associated cost breakdown as a function of load factor for 2035

In a cost-efficient system based on dispatchable generation, the bulk of generation would be provided by nuclear power. A wide range of power CCS technologies, including NGCCs with post combustion capture, could play a role in such a future power system complementing nuclear generation. The dispatchable fleet in this system comprised 27 GW of nuclear, 15 GW NGCC with post combustion capture, and 40 GW blue H2CCs – as shown in Figures 2a and 2b.

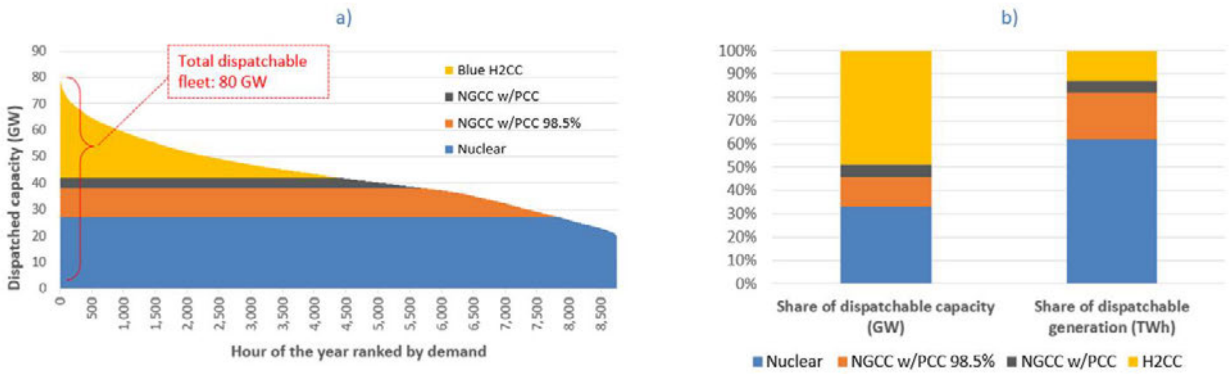


Figure 2a: Load duration curve and corresponding dispatch of installed generation in scenario Dispatchable; and **2b:** Breakdown of installed capacity and generation of dispatchable generation technology in scenario Dispatchable

A system based on VRE generation requires almost the same amount of dispatchable generation capacity as a system without VRE generation. Sufficient dispatchable generation capacity could thus be a key enabler to achieving high VRE penetration while ensuring security of supply and lowest cost. However, the dispatchable generation capacity is utilised at much lower rates than in a system without VRE generation. The modelling indicated that the average load factor of the dispatchable fleet in a system with high VRE penetration would be below 15%. This would imply that H2CCs are better suited to complement wind and solar in systems of high VRE penetration than NGCCs w/ PCC and nuclear plants. In the scenario with high VRE penetration and no storage, the installed capacity of H2CCs is 68 GW, while only 4 GW of NGCCs w/ PCC and no nuclear generation were deployed – see Figures 3a and 3b.

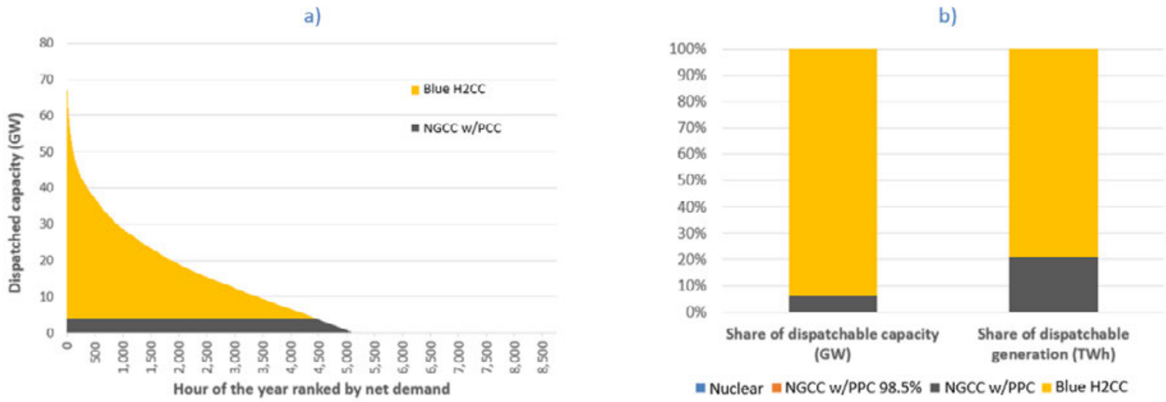


Figure 3a: Load duration curve and corresponding dispatch of installed generation in scenario VRE; and **3b:** Breakdown of installed capacity and generation of dispatchable generation technology in scenario VRE

In one scenario of the analysis with high VRE penetration, battery and H_2 power-to-power storage (consisting of electrolysers, H_2 storage, and green H2CCs) were deployed to utilise renewable generation that would otherwise have been curtailed. The optimal installed capacity of batteries and green H2CCs in this scenario was 9 GW and 30 GW, respectively. This left a significant remaining requirement for dispatchable generation, which was met by 32 GW blue H2CCs and 3 GW NGCCs w/ PCC, as shown in Figures 4a and 4b.

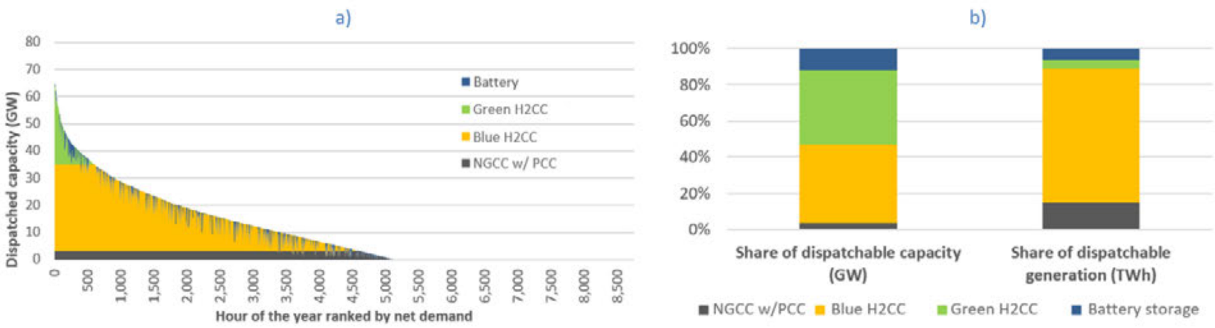


Figure 4a: Load duration curve and corresponding dispatch of installed generation in scenario VRE+storage; and **4b:** Breakdown of installed capacity and generation of dispatchable generation technology in scenario VRE+storage

Despite the requirement for significant dispatchable capacity as backup power, a system with high VRE penetration was shown to have **similar or even slightly lower** generation cost than one based on dispatchable generation technologies only (see Figure 5). Decisions on the future power generation mix and the choice between blue and green H_2 would consider not only costs but also wider policy drivers such as a reliance on energy imports as well as environmental and supply chain concerns. For example, prioritising a reduction in natural gas imports (particularly in the UK) and avoidance of upstream natural gas emissions would likely lead to a preference for green H_2. On the other hand, scarcity of raw materials and skills required for electrolysers as well as infrastructure bottlenecks due to slow electricity network upgrades and long permitting procedures that might be required for VRE expansion might lead to a preference for blue H_2, i.e., natural gas pre-combustion CCS.

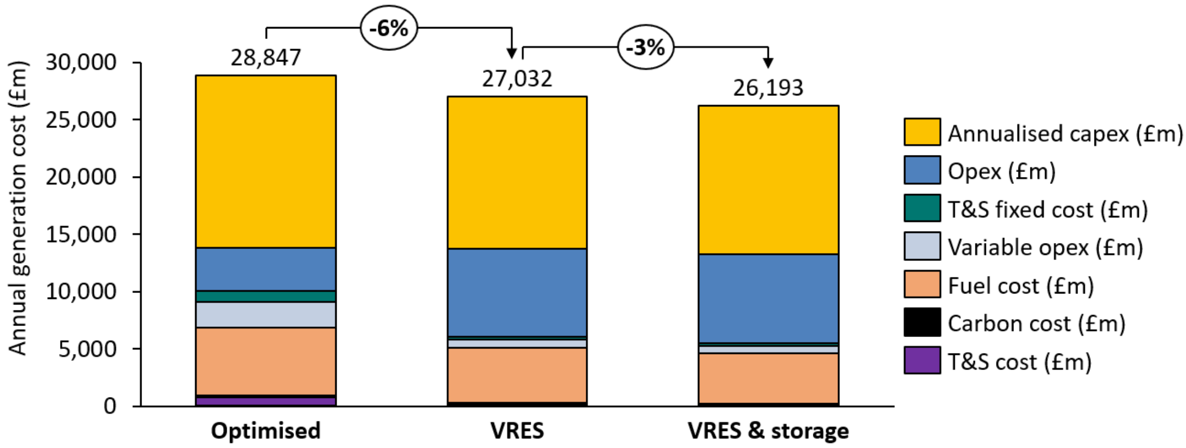


Figure 5: Annual generation cost for the modelled scenarios

Modelling assumptions and caveats

The modelling was based on a number of assumptions and caveats which presents uncertainties in the findings:

- The VRE penetration was an exogenous input and was not optimised. A higher VRE penetration would reduce the generation from (but not necessarily the capacity of) power CCS technologies in the system and, furthermore, would increase the benefits of storage to the system and might lead to a higher deployment of storage capacity.
- The benefits of energy storage on network cost savings were not investigated. Accounting for these benefits would likely increase the installed storage capacity in the model.
- The cost for blue H2 does not change depending on its utilisation. This assumes a liquid market for blue H2 allowing power plants to purchase it according to demand at a stable price. However, if the power plant were procuring blue H2 from a dedicated facility adjacent to the power plant, the price would likely fluctuate according to demand, e.g., the price could increase should demand fall (due to lower utilisation of the power CCS facility).
- Green H2 production need not be limited to curtailed generation only. Green H2 might also be produced by dedicated VRE plants.
- NOAK costs assigned to future technologies remain uncertain. This is the case particularly for commercially immature technologies such as power plants with post-combustion CO_2 capture and new nuclear reactors. Given such uncertainties and the relatively small cost differences between some of the scenarios, such scenarios may be considered as having similar generation costs.
- Results are highly sensitive to assumed fuel prices. A higher price for natural gas would significantly increase the total cost in some scenarios but have only limited impact on costs in others where the majority of generation is provided by VRE.

Expert Review Comments

On balance, the report was warmly welcomed by the expert reviewers. The modelling and the conclusions drawn were considered sound. Comments raised were fully addressed by the authors. While some comments led to explanations, modifications or additions to the text, others were noted as being beyond the scope of the study, with some included in the suggestions for future work.

A concern was raised over the use of LCOE as the metric to compare technologies. While the approach was widely accepted when the grid comprised predominantly thermal generation technologies, as VRE technologies are increasing their penetration, concerns over the use of LCOE have since become more pronounced. Noting that LCOE as a metric for comparing technologies is still employed by many in the modelling community, alternative approaches have been gaining traction – for example, the use of 'total system cost' or investigating the 'value' of technologies rather than their cost (also see Footnote 22).

As is the case for any modelling activity, the outputs are contingent on the input data and the assumptions made. While some discussion on the impacts of the assumptions is included in the report, a full quantitative assessment was outside the scope of the study. Several of the concerns raised regarding the impact of the assumptions were included by the authors in their suggestions for further work.

The report presented generation mixes for the UK based on new-build data, which was considered an important first step. However, it was pointed out, as a next step, that government and power fleet operators would find interest in an estimated cost-optimal generation mix that accounted for assets already in operation or in construction, assets that would be retired and those that might reasonably be retrofitted with CCS.

In response to two specific questions raised:

- The authors explained that the role of battery storage could indeed be compared to that of gas CCS when considering the amount of otherwise curtailed generation from an oversized renewable energy capacity. Therefore, both battery and gas CCS technologies were grouped under dispatchable generation considering the oversupply from VRE technologies based on the UK's historical weather data.
- While H2CC technology was currently under development, the authors assumed that it would reach NOAK by 2035. In fact, the authors assumed that all low carbon generation technologies addressed in the study would reach NOAK maturity by 2035.

Conclusions and Recommendations

The primary objective of this study was to explore the potential for further reductions in the costs of CO_2 capture. The increasing penetration of intermittent renewable technologies is leading to reduced demand from the more traditional generators, as it will do from those deploying CCS. Driving down the CAPEX and OPEX of CO_2 capture processes will be essential for them to contribute to grid reliability and to provide electricity at a competitive cost.

To achieve CAPEX reductions, key drivers include the scaling up of capture plants, off-site manufacturing through modularisation, developing the CCS supply chain, flue gas recirculation for NGCC power plants, and capture plant de-risking. To reduce the OPEX component, the most attractive opportunities at present include reducing amine degradation, optimising the heat integration between the host unit and the capture plant, and lowering maintenance costs.

While current large-scale power CCS projects may rely on bespoke, first-of-a-kind, CO_2 capture units, technology innovation will drive costs down. Multiple CO_2 capture technologies solutions are emerging that consider novel construction techniques, design modifications and logistics while aiming to achieve capture rates in excess of 95%. For a number of reasons, the impact of these innovations to the cost of power CCS is not yet fully understood, partly due to the sensitivities surrounding access to cost information. However, there are insights to be had from information available in the public domain, e.g., from multiple studies and published papers, FEED studies, projects that are currently operational, those in advanced development, as well as previous demonstrators that help understand the key cost drivers.

While the success of a capture technology will depend on reductions in CAPEX and OPEX, where and how these reductions are likely to occur are the fundamental questions. For example, cost savings may arise from technological advances, capital and commissioning improvements, operational developments and/or design modifications. Results from this study will be helpful in devising future policy in support of power CCS and in assessing the potential impact of implementing the policy.

An LCOE model was developed to explore the costs for dispatchable generation and the role that power CCS technologies could play in providing back-up to VRE technologies, i.e., solar and wind. Alongside several power CCS technologies, other flexible options included battery energy storage and nuclear power.

Results showed that, for a fully decarbonised energy mix for dispatchable power in 2035, battery storage was optimal to provide dispatchable generation for low load factors, with nuclear offering the lowest LCOE for load factors above 90%. Load factors between 30 and 45% were satisfied by blue H2CC (a pre-combustion capture technology) and natural gas with carbon capture (post-combustion capture) was found to be optimal in terms of LCOE when providing dispatchable generation for load factors between 50 and 85%.

Having declared the goal of largely decarbonising its power system by 2035, the UK was selected as a case study to explore the role of power CCS in a future decarbonised power system. Several potential generation mixes of a largely decarbonised power system in the UK in 2035 were modelled. Despite the requirement for significant dispatchable capacity as back-up power, the modelling suggested that a system with high VRE penetration had a similar or even slightly lower generation cost than a system based on dispatchable generation technologies only.

In a cost-efficient system based on dispatchable generation, nuclear power was a key technology, operating at load factors above 85%. A wide range of power CCS technologies, including NGCCs with post combustion capture, could play a role in such a future power system complementing nuclear generation. Blue H2CC was shown to be the most economic power CCS technology due to its lower CAPEX compared to post-combustion capture plants.

In all cases, whether in a system comprising only dispatchable technologies or in a system with high VRE penetration, power CCS was included as a cost-effective technology providing flexible, low carbon, dispatchable power generation. In fact, systems with and without VRE technologies were found to require similar amounts of dispatchable generation capacity. Sufficient dispatchable generation capacity was identified as a key enabler to achieve high VRE penetration while ensuring security of supply. However, the dispatchable generation capacity would be utilised at much lower rates than in a system with no VRE generation.

The average load factor of the dispatchable fleet (i.e., comprising natural gas combined cycle (NGCC) with post-combustion capture, blue H2CC and nuclear) in a system with high VRE penetration was less than 15%. The total generation capacity (dispatchable generation plus VRE generation) in such a system was more than twice the capacity in a system without VRE. A significant requirement for dispatchable generation remained even when batteries were deployed as flexible generation options.

However, it is important to note that the composition of the future generation mix will not depend wholly on costs. For example, decisions on the future power generation mix and the choice between deploying blue hydrogen, green hydrogen or both would factor in concerns around energy security, seasonal variability in demand would likely require the availability of thermal generation and, of course, environmental and supply chain challenges would need to be addressed. Moreover, storage and flexibility would not be limited to batteries and H2CC alone. For example, demand side response from electric vehicles and heat pumps could improve the case for battery storage and green hydrogen – which could, however, further reduce opportunities for power CCS plants.

Suggestions for Further Work

While the role of power CCS technologies in future power systems has been assessed, some aspects remained out of scope and may merit future examination:

- In this analysis, the VRE penetration was fixed as an exogenous assumption. Further analysis varying the VRE penetration would provide additional insight on the cost optimal generation mix in a zero-carbon power system.
- Likewise, further insights would be gained by extending the analysis to investigate the impact of demand side response from electric vehicles and thermal storage, a faster roll out of electric vehicles and heat pumps, and the impact of higher natural gas prices.
- Security of supply was out of scope. While the analysis ensured there was sufficient capacity to meet demand in an average year, system stress events and other security of supply considerations might usefully be addressed. Consideration of cross-sectoral effects of the energy transition and the necessity for security of supply regarding electric power, heating, fuels and feedstock for households, industry, and transport according to the fluctuating demand would result in a more wholistic picture of the energy system.
- The analysis does not account for the spatial constraints and network representations of an electricity grid. Modelling of these elements would be required to assess the cost of grid expansion and the total system cost for different generation mixes.
- Non-cost factors such as the level of natural gas imports in largely decarbonised energy systems of the future and the implied geo-political risk could be considered and, to better inform potential policy development, supply chain and infrastructure risks of systems largely based on VRE technologies warrant further assessment.
- Data for new-build generation plant were used in the analysis and did not account for pre-existing generators within the UK. Incorporating pre-existing power assets, some of which would be retired over time or, potentially, retrofitted with CCS might usefully be explored.
- The analysis does not incorporate demand side response measures or the use of interconnectors. Both DSR and interconnectors could reduce the need for dispatchable generation or for battery storage. Incorporating DSR and use of interconnectors into the model might be of interest.

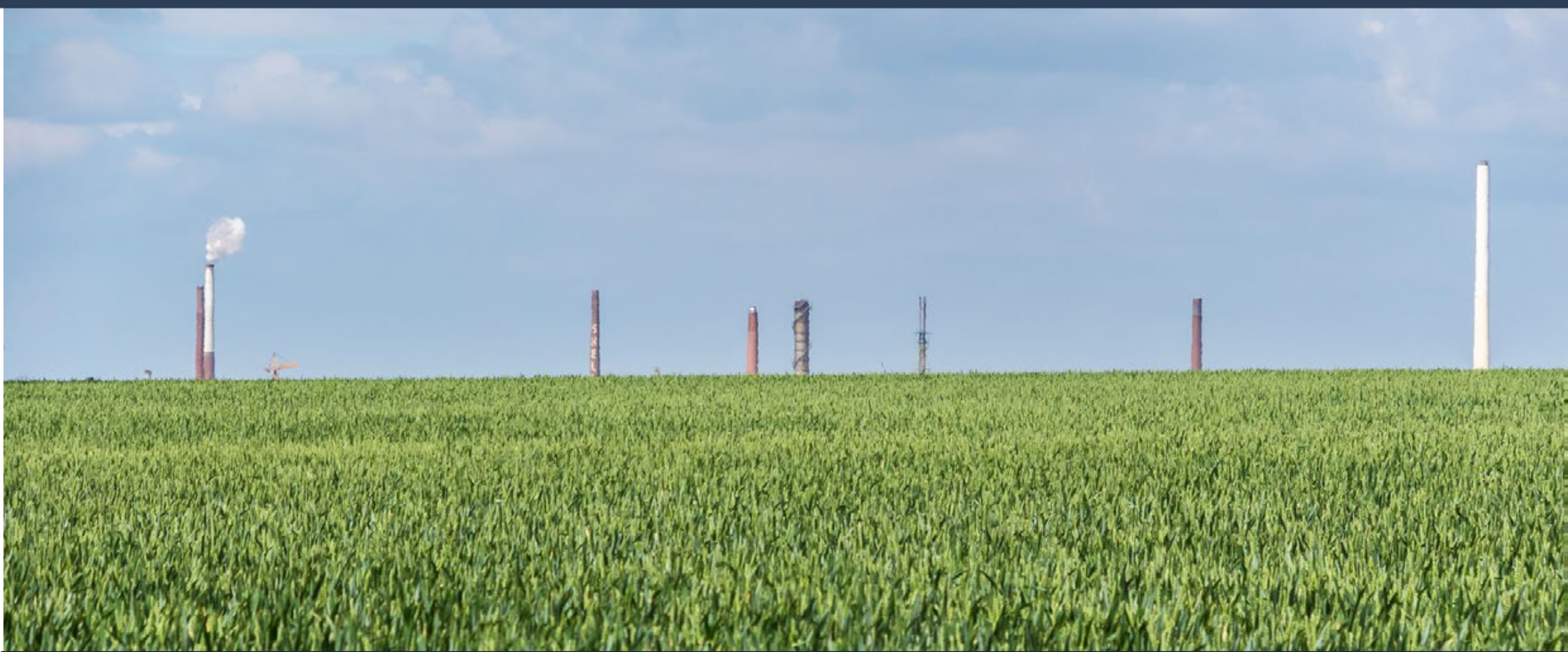
elementenergy
an ERM Group company

POWER CCS: POTENTIAL FOR COST REDUCTIONS AND IMPROVEMENTS

A report for the

IEAGHG

Element Energy



Element Energy Limited, 33 St Mary Axe, London EC3A 8AA   tel +44(0)203 206 5900

Executive Summary

This study assesses CCS costs and integrates these insights into a techno-economic analysis of power CCS[1] and other power generation options to explore the role that power CCS technologies can play in the generation mix of a largely decarbonised power system.

Carbon capture and Storage (CCS) technologies can decarbonise existing and new fossil fuel generation assets by capturing the CO_2 emissions produced from combustion and storing the captured CO_2 in geological formations. Despite **wide acknowledgement of the potential for power CCS to decarbonise the power system**, only two thermal power plants (Boundary Dam and Petra Nova)[2] have thus far commercially deployed and operated large-scale CO_2 capture plants. With several additional projects in advanced development and others in earlier stages of planning, power CCS could finally be taking off. Several technology options are under development to decarbonise thermal power generation, with post-combustion amine-based absorption technologies leading the way and some pre-combustion and oxy-combustion CO_2 capture projects also under development.

Lessons learned from the deployment of CO_2 capture at Boundary Dam, Petra Nova and numerous pilots can lead to reductions in CCS costs. Previous reports by the IEAGHG, the UK Department for Business, Energy and Industrial Strategy (BEIS), and the U.S. Department of Energy's National Energy Technology Laboratory (NETL) provide bottom-up cost estimates for CO_2 capture on thermal power generation. The extent to which power CCS can reduce its cost will be critical to determine the role it can play in future power systems to provide dispatchable electricity, given that variable renewable energies are, in many cases, already providing lower cost power than unabated thermal power generation.

It is important to develop an **understanding of cost reduction opportunities for power CCS and the role it can play in future power system**. To bridge the knowledge gap, Element Energy was commissioned by IEAGHG to review publicly available literature and collective input from technology developers and industry partners to:

- **Build an understanding** of the potential to further reduce costs of power CCS.
- **Provide a techno-economic analysis** of power CCS and its potential competitiveness compared to alternative flexible power generation options to integrate variable renewable energy (solar/wind) with technologies such as battery storage.
- **Investigate several potential generation mixes** of a largely decarbonised power system, taking the UK in 2035 as an example, and explore the role that power CCS technology could play..

Carbon capture technologies with high potential to be deployed in the near- and medium-term were progressed to the techno-economic assessment.

In the long term, many capture technologies mentioned in this report could potentially demonstrate merits to capture a significant share of power CCS deployment. However, **for the present analysis only options with a high near- and medium-term potential (before the mid-2030s) are included**. Post-combustion is the primary method proposed for use in existing power plants, with amine-based absorption being the most mature technology having been used in Boundary Dam and Petra Nova. Oxy-fired supercritical power generation, or the Allam cycle, was also taken forward to the techno-economic assessment due to a relatively high maturity, with several commercial projects under development. The techno-economic assessment thus includes:

- Natural gas combined cycle (NGCC) power plant with post-combustion capture
- Super critical pulverised coal (SCPC) power plant with post-combustion capture
- Oxy-fired supercritical power generation (Allam cycle)[3]

[1] The term power CCS refers to any form of thermal electricity generation with carbon capture and storage (CCS) technologies attached.
[2] Boundary Dam and Petra Nova are coal-based power plants.
[3] The Allam cycle has a lower TRL than the other capture methods.

Whilst it is now understood that capture rates higher than 90% are feasible and can have a limited impact on costs, the 90% capture rate has been the baseline target for years and has been the focus of most studies to date.[4] **A 90% capture rate constitutes the base case for the techno-economic model. Capture rates higher than 95% were also modelled to incorporate the evolving drive towards higher capture rates**.

Cost estimates for power CCS were built on multiple publicly available bottom-up cost models

Three main sources of bottom-up data were identified through the literature review to be fed into the techno-economic assessment: Wood's report for BEIS in 2018 on next generation capture technologies[5] the IEAGHG's benchmarks from 2020,[6] and the U.S. Department of Energy's National Energy Technology Laboratory (NETL) Cost and Performance Baseline for Fossil Energy Plants.[7] Cost metrics were derived from these reports and taken forward to the techno-economic assessment.

Technology	Reference	CAPEX (£/kW)	Fixed OPEX (£/kW/y)	Variable OPEX (£/MWh)	Net power output (MW)	Fuel efficiency (LHV)	Capture rate	Share of biomass (% of energy input)
NGCC w/o PCC	IEAGHG benchmarks	746	21	0.5	1,506	59.0%	-	0%
SCPC w/o PCC	NETL	2,037	56	6.1	650	41.6%	-	0%
NGCC w/ PCC	IEAGHG benchmarks	1,470	41	1.1	1,344	52.7%	90%	0%
SCPC w/ PCC	NETL	3,668	95	11.0	650	32.5%	90%	0%
SCPC w/ PCC + biomass co-firing	NETL	3,834	98	11.2	650	31.8%	90%	8.1%
BECCS	BEIS	3,392	158	28.3	396	30.6%	90%	100%
Allam cycle	BEIS	1,541	70	7.0	848	52.3%	90% [8]	0%
SCPC w/ PCC 99%	NETL	3,844	99	11.8	650	30.9%	99%	0%
NGCC w/ PCC 98.5%	IEAGHG benchmarks	1,583	44	1.2	1,316	51.6%	98.5%	0%

Multiple cost reduction opportunities were identified and prioritised, with some of them applying to CAPEX and others to OPEX

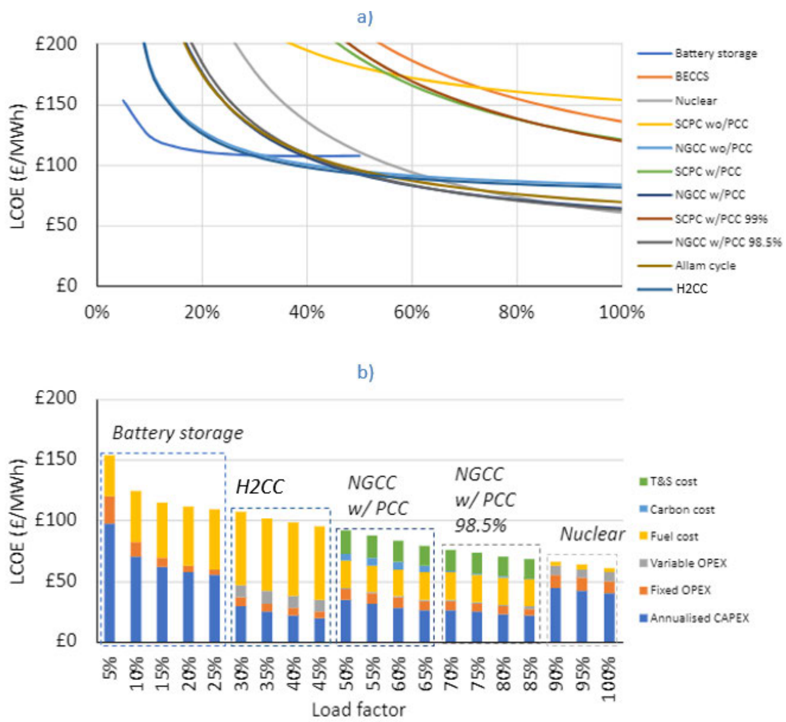
CAPEX reductions are particularly important for cost-effective power CCS facilities, as it is anticipated that future operation may be at lower-than-baseload load factors to support the higher penetration of variable renewable energy. At low load factors, the CAPEX is spread across a reduced number of operating hours, and hence the CAPEX share in the LCOE increases. Measures that target reductions in CAPEX are therefore very important to improve the economics of future CCS installations deployed in the power sector. Among the different CAPEX reduction opportunities, **scale-up of the CCS plant**, **site layout and modularisation**, **development of a CCS supply chain**, **flue gas recirculation,[9]** and **capture plant de-risking** were identified as the priority areas for action. OPEX also contributes significantly towards the overall cost of a CCS facility. Most of this is related to the thermal energy and steam generation requirements to separate the CO_2 from the

[4] IEAGHG (2019) Towards zero emissions CCS with biomass or higher capture rates.
[5] Assessing the Cost Reduction Potential and Competitiveness of Novel (next Generation) UK Carbon Capture Technology, Wood, October 2018
[6] Update Technoeconomic Benchmarks for Fossil Fuel-Fired Power Plants with CO_2 Capture, IEAGHG, TR 2020-07, July 2020.
[7] Cost and Performance Baseline for Fossil Energy Plants Volume 1, Revision 4, US Department of Energy. September 2019.
[8] The Allam cycle can achieve capture rates over 95%. The 90% figure reflects the age of the study and is not linked to the technical potential to achieve very high capture rates.
[9] Flue gas recirculation also brings significant OPEX reduction opportunities.

flue gases (in the case of post-combustion) or the waste gases (in the case of pre-combustion or oxy-fuel approaches). The most important action areas for OPEX reduction opportunities were identified as **lowering amine degradation**, **maintenance costs** and **optimisation of heat integration**.

At low load factors pre-combustion is more competitive than post combustion

This study also aims to provide a techno-economic analysis of power CCS and its potential competitiveness compared to alternative flexible power generation options to back up variable renewable energy (solar/wind). Such options include battery energy storage, which can compete with dispatchable generation at low load factors. We furthermore investigate the relative competitiveness of natural gas pre-combustion CCS, i.e. blue Hydrogen Combined Cycle gas turbines (blue H2CCs),[10] versus Natural Gas Combined Cycle gas turbines with post-combustion capture (NGCCs w/ PCC) depending on the utilisation of the plants. These cost estimates consider the impact of any learnings from power CCS demonstration projects as assessed in the first part of the study. Based on the assumptions used in this study, **in 2035 due to their lower CAPEX requirements,[11] blue H2CCs are more cost efficient than NGCCs w/ PCC below load factors of 50%.[12] NGCCs w/ PCC on the other hand are more cost competitive than nuclear generation at load factors below 90%** (cp. figure below).



(a) LCOE for various power generation technologies and (b) best LCOE with an associated cost breakdown as a function of load factor for 2035

Similar costs of dispatchable and variable renewable systems

Finally, the study investigates several potential generation mixes of a largely decarbonised power system in the UK in 2035 and explores the role that power CCS technology could play in those. This builds on the techno-economic analysis described above by deploying generation technologies in a cost optimal way given different constraints. We are investigating power generation mixes based on dispatchable generation technologies including nuclear and power CCS, as well as those predominantly based on variable

[10] This assumes a separate blue hydrogen plant and hydrogen gas turbine – it does not reflect costs for an Integrated Gasification Combined Cycle (IGCC).

[11] The cost of H_2 gas turbines are equated with CCGTs based on promising results from examples of H2 mixing in CCGTs. However, no techno-economic data exists validated by real tests of 100% H2GT and regulative questions remain unanswered (for example NOx formation and the cost of deNOx systems).

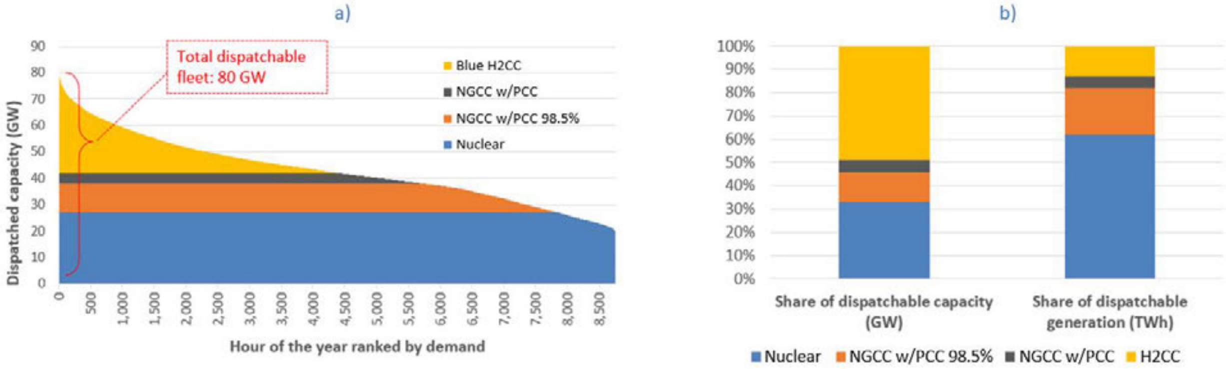
[12] The modelling assumes blue H_2 supply exactly meets H_2 demand meaning that the requirement for blue H_2 is determined by the load factor.

renewable energy, and we compare their total annual costs. A key focus of the analysis is the optimal deployed capacity of power CCS technologies in these different versions of a future UK power system and their utilisation. The study assumes significant increase of electricity demand in the UK in 2035, driven by electrification in heat, transport, and industry and leading to a peak demand of 82 GW compared to 54 GW today (52% increase). **Based on the assumptions used in the analysis, a power system based on Variable Renewable Energy (VRE) and a system based on dispatchable low carbon generation could have similar costs**. In both systems, power CCS technologies could provide flexibility to the power system in form of dispatchable power generation. Three cost-optimal scenarios are presented:

- Scenario Dispatchable presents an optimised mix of low carbon dispatchable fleet without renewables
- Scenario VRE presents a mix with high renewable penetration and a cost-optimal dispatchable fleet
- Scenario VRE + storage presents a mix with high renewable penetration, battery energy storage, H_2 power to power storage, and a cost-optimal dispatchable fleet

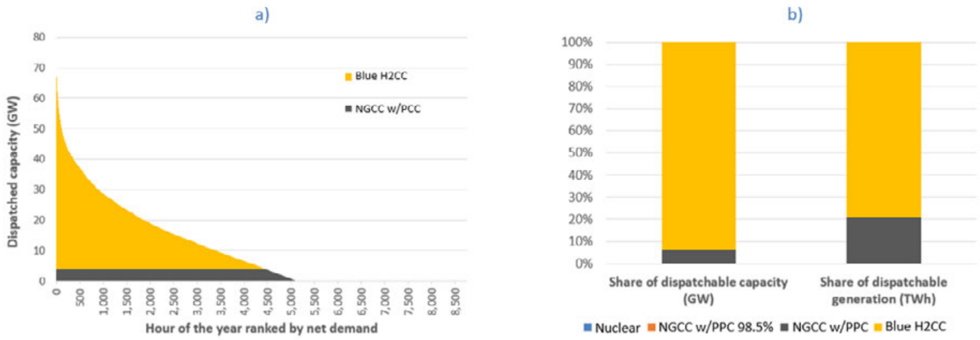
Electricity generation based on dispatchable generation only is more expensive than one where dispatchable generation complements VRES

In a cost-efficient system based on dispatchable generation, the bulk of generation would be provided by nuclear power. A wide range of power CCS technologies, including NGCCs with post combustion capture, could play a role in such a future power system complementing nuclear generation. The dispatchable fleet in this system consists of 27 GW of nuclear, 15 GW NGCC with post combustion capture, and 40 GW blue H2CCs (figure below).



(a) Load duration curve and corresponding dispatch of installed generation in scenario Dispatchable; and (b) breakdown of installed capacity and generation of dispatchable generation technology in scenario Dispatchable

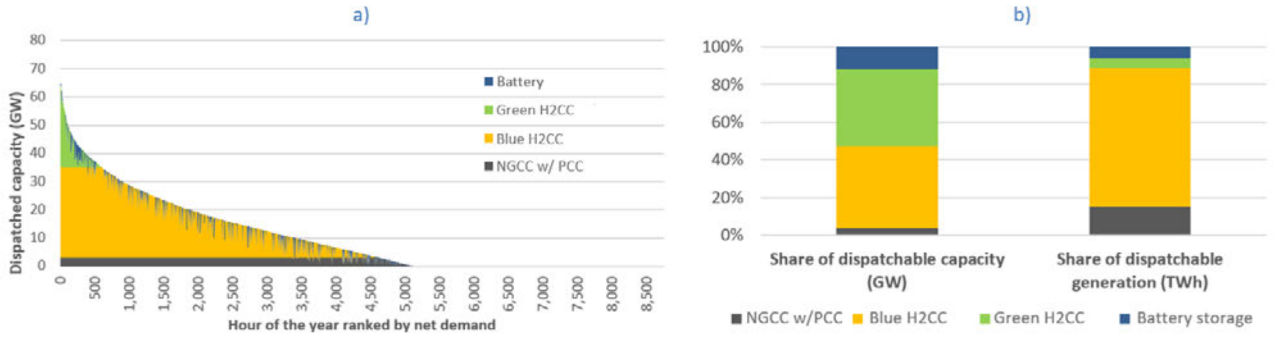
A system based on VRE generation requires almost the same amount of dispatchable generation capacity as a system without VRE generation. Sufficient dispatchable generation capacity could thus be a key enabler to achieve high VRE penetration while ensuring security of supply and lowest cost. However, this dispatchable generation capacity is utilised at much lower rates than in a system without VRE generation. In our modelling, the average load factor of the dispatchable fleet in a system with high VRE penetration is below 15%. This implies that **H2CCs are better suited to complement wind and solar in systems of high VRE penetration than NGCCs w/ PCC and nuclear plants**. In the scenario with high VRE penetration and no storage, the installed capacity of H2CCs is 68 GW, while only 4 GW of NGCCs w/ PCC and no nuclear power plants are deployed (figure below).



(a) Load duration curve and corresponding dispatch of installed generation in scenario VRE; and (b) breakdown of installed capacity and generation of dispatchable generation technology in scenario VRE

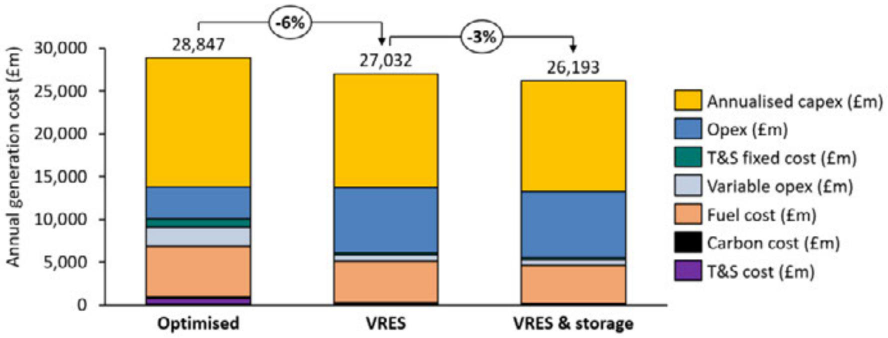
Significant remaining requirement for dispatchable generation with storage

In one scenario of the analysis with high VRE penetration, battery and H_2 power to power storage (consisting of electrolysers, H_2 storage, and Green H2CCs) are deployed to utilise renewable generation that would otherwise be curtailed. The optimal installed capacity of batteries and green H2CCs in this scenario is 9 GW and 30 GW respectively. This leaves a significant remaining requirement for dispatchable generation, which is met by 32 GW blue H2CCs and 3 GW NGCCs w/ PCC (figure below).



(a) Load duration curve and corresponding dispatch of installed generation in scenario VRE+storage; and (b) breakdown of installed capacity and generation of dispatchable generation technology in scenario VRE+storage

Despite the requirement for significant dispatchable capacity as backup power, a system with high VRE penetration has similar or even slightly lower generation cost than one based on dispatchable generation technologies only (cp. figure below). Decisions on the future power generation mix and the choice between blue and green H_2 will consider not only costs but also wider policy drivers such as reduction of reliance on energy imports as well as environmental and supply chain concerns. For example, prioritising reduction of natural gas imports (particularly in the UK) and avoidance of upstream natural gas emissions will lead to a preference for green H_2. On the other hand, scarcity of raw materials and skills required for electrolysers as well as infrastructure bottlenecks due to slow electricity network upgrades and long permitting procedures that might be required for VRE expansion might lead to a preference for blue H_2, i.e. natural gas pre-combustion CCS. These factors were not the focus of this study.



Annual generation cost for the modelled scenarios

Recommendations for future work

While the modelling results of this study have important implications for the role of power CCS technologies in future power systems, several aspects remained out of scope and warrant further investigation. These include the **optimal VRE penetration in a highly renewable system, impact of demand side response from electric vehicles and thermal storage, a faster roll out of electric vehicles and heat pumps, as well as the impact of higher natural gas prices**. Also, while the analysis ensures that there is sufficient capacity to meet the demand in an average year it does not explore extreme system stress events or other security of supply considerations. In relation to this, the analysis does not account for the spatial constraints and network representations of an electricity grid. We thus recommend exploring these aspects in future studies on this topic. Furthermore, non-cost factors such as the level of natural gas imports in future largely decarbonised energy systems and the implied geo-political risk, and supply chain and infrastructure risks of systems largely based on VRE warrant further assessment to inform policy choices.

Authors

This report has been prepared by **Element Energy** for the International Energy Agency's Greenhouse Gas R&D Programme (IEAGHG).

Element Energy (an ERM Group Company) is a leading low carbon energy consultancy working in a range of sectors including carbon capture and storage, low carbon transport, low carbon buildings, renewable power generation, energy networks, and energy storage. Element Energy works with a broad range of private and public sector clients to address challenges across the low carbon energy sector and provides insight and analysis across all parts of the CCS chain.

ERM is a multinational consultancy firm which focuses on sustainability. The company provides environmental, health, safety, risk, and social consulting services and sustainability related services. ERM provide expertise in strategic advisory, concept development, techno-economic feasibility, and is a leading company supporting CCS projects.

Study authors

Silvian Baltac	Associate Partner	Freddie Barnes	Senior Consultant
Foaad Tahir	Technical Director	Ignacio Rabsiun	Senior Consultant
Elian Pusceddu	Principal Consultant	Alexander Fish	Consultant
Michael Joos	Senior Consultant	Luke Hatton	Consultant

For comments or queries please contact: CCSindustry@element-energy.co.uk

License-free content uses

Front cover image from Pixabay.

Acknowledgments

To ensure the quality and technical integrity of the research undertaken by IEAGHG each study is managed by an appointed IEAGHG manager. The report is also reviewed by a panel of independent technical experts before its release.

The IEAGHG manager for this report was: Keith Burnard.

The expert reviewers for this report were:

- Nathan Bongers and Damian Dwyer, Australia
- DESNZ
- Drax
- RWE
- Richard Esposito, Southern Company
- Suzanne Ferguson, Wood

Disclaimer

While the authors consider that the data and opinions contained in this report are sound, all parties must rely upon their own skill and judgement when using it. The authors do not make any representation or warranty, expressed or implied, as to the accuracy or completeness of the report. There is considerable uncertainty around the future cost reductions of CO_2 capture and other power generation technologies. The authors assume no liability for any loss or damage arising from decisions made based on this report. The views and judgements expressed here are the opinions of the authors and do not reflect those of IEAGHG or any of the stakeholders consulted during this project.

Abbreviations and Acronyms

ASU	Air Separation Unit
BECCS	Bioenergy with Carbon capture and Storage
BEIS	UK Government Department for Business, Energy, and Industrial Strategy
BESS	Battery Energy Storage System
BOS	Battery Optimization System
CAPEX	Capital Expenditure
CCG	Combined Cycle Gas Turbine
CCS	Carbon capture and Storage
CHP	Combined Heat and Power
CO_2	Carbon Dioxide
DCC	Direct Contact Cooler
DSR	Demand Side Response
EOR	Enhanced Oil Recovery
EPC	Engineering, Procurement and Construction
FEED	Front End Engineering Design
FES	Future Energy Scenario
FOAK	First of a Kind
H_2	Hydrogen
H_2CC	Hydrogen Combined Cycle
H2P2P	Hydrogen Power to Power
IEA	International Energy Agency
IGCC	Integrated Gasification Combined Cycle
IRCC	Integrated Reforming Combined Cycle
IRENA	International Renewable Energy Agency
LCOE	Levelized Cost of Electricity
LHV	Lower Heating Value
MCFC	Molten Carbonate Fuel Cell
NETL	U.S. Department of Energy's National Energy Technology Laboratory
NGCC	Natural Gas fired Combined Cycle Gast Turbine
NGESO	National Grid Electricity System Operator
NOAK	N^{th} of a Kind
NREL	National Renewable Energy Laboratory
OCGT	Open Cycle Combined Turbine
OPEX	Operational Expenditure
PCCS	Power CCS
PSA	Pressure Swing Adsorption
SCPC	Super Critical Pulverised Coal
SOAK	Second of a Kind
T&S	Transport and Storage
TEA	Techno-Economic Assessment
TRL	Technology Readiness Level
TSA	Temperature Swing Adsorption
VPSA	Vacuum Pressure Swing Adsorption
VRE	Variable Renewable Energy
VRES	Variable Renewable Energy Sources

Contents

1. Introduction

1.1 Context

Carbon capture and Storage (CCS) technologies can decarbonise existing fossil fuel generation assets by capturing the CO_2 emissions produced from combustion and storing the captured CO_2 in geological formation or using it in products with long lifetimes (e.g., construction materials). CCS offers a unique decarbonisation approach to **reduce emissions from 'hard-to-abate' sectors such as steel, lime and cement and prevent the risk of stranded assets in the power sector.**

CCS technologies for use across a range of sectors have been recognised by the Intergovernmental Panel on Climate Change as **vital to achieving the 1.5ºC global climate target.** The UK's Sixth Carbon Budget, produced by the Climate Change Committee and detailing the UK's route to net zero emissions by 2050 in its Balanced Pathway, recommends that by 2050, the UK should be capturing up to 104Mt CO_2 annually across all sectors, including up to 9.6 Mt CO_2 per annum in the power sector. However, to date there are no large-scale active CO_2 capture and storage projects within the UK.

Several technology options are under development to decarbonise thermal power generation. Multiple options for pre-, oxy-, and post-combustion CO_2 capture are currently investigated across the world. Only two thermal power plants, Boundary Dam and Petra Nova, have commercially deployed CO_2 capture at a large scale, but multiple other thermal power plants have trialled CCS technologies with smaller slipstreams. For instance, the Bellingham natural gas combined cycle (NGCC) power plant in Massachusetts demonstrated CO_2 capture from a 40 MW slipstream between 1991 and 2005.[13] In addition, a number of additional projects are in advanced development. In the near- to medium-term, growth in the sector is expected to be led by post-combustion amine-based absorption capture technologies, although some commercial-scale Allam cycle power plants are also under development. These set of technologies with greater near- to mid-term potential are the focus of this study. Previous reports by the IEAGHG, the UK Department for Business, Energy and Industrial Strategy (BEIS), and the U.S. Department of Energy's National Energy Technology Laboratory (NETL) provide bottom-up cost estimates for CO_2 capture on thermal power generation. Data from those reports have fed into the assumptions for the techno-economic assessment.

Lessons learned from the deployment of CO_2 capture at Boundary Dam, Petra Nova and numerous pilots have led to reductions in CCS costs. A long list of cost reduction opportunities for power CCS was developed for this study, drawing from sources in the literature as well as project expert input. To achieve CAPEX cost reductions, key drivers are scaling up capture plants, off-site manufacturing through construction modularisation, developing a CCS supply chain, flue gas recirculation for natural gas combined cycle power plants, and capture plant de-risking. To reduce the OPEX component, the most attractive opportunities include reducing amine degradation, optimising the heat integration between the host unit and the capture plant, and lowering maintenance costs.

Whilst the previous and current power CCS projects may rely on bespoke, one-of-a-kind, CO_2 capture units, technology innovation may drive costs down. Multiple CO_2 capture technologies solutions are emerging on the market, including new modular technologies, such as those developed by Aker CO_2 capture or CO_2 Solutions, considering novel construction techniques, design modifications (e.g., addition of lean solvent tanks, sizing, and changes to the flow rates in the absorber/regenerator) and logistics whilst aiming to achieve capture rates of at least 95%. The impact of these innovations to the cost of power CCS is not fully understood, partially due to the commercial sensitive information held by technology developers. However, there are insights to learn from multiple studies and papers, projects that are currently operational, those in advanced development, as well as any previous demonstrators, such as the Petra Nova (USA) and UK proposed projects (White Rose, Peterhead I, Longannet, and Kingsnorth) that conducted FEED studies. These could help understand the key cost drivers associated with power CCS and could offer insights into future improvements.

[13] Other examples include Schwarze Pumpe in Germany, Pleasant Prairie in the USA, Ferrybdrige in the UK, or Callide-A in Australia.

1.2 Objectives & scope

The primary objective of this study is to provide an understanding of the potential to further reduce costs and to fully appreciate the benefits of power CCS. CO_2 capture is widely seen as an essential tool for decarbonisation of the power sector (including natural gas and coal). In this context, this study aims to specifically understand how cost reductions could be achieved, considering various drivers and levers including operational aspects, technological developments (including various technologies such as pre-, oxy- and post-combustion capture) and design modifications (e.g., stick built vs. modularisation) to enable mass-production.

The study also aims to provide a techno-economic analysis of power CCS and their potential competitiveness compared to alternative flexible power generation options to integrate variable renewable energy (solar/wind) such as battery storage. We also investigate the relative competitiveness of natural gas pre-combustion CCS (Blue Hydrogen NGCCs) versus post-combustion CCS depending on the utilisation of the plants. These cost estimates consider the impact of any learnings from power CCS demonstration projects.

Finally, we investigate several potential generation mixes of a largely decarbonised power system in the UK in 2035 and explore the role that power CCS technology could play in those. This builds on the techno-economic analysis of the previous chapter by deploying generation technologies in a cost optimal way given different constraints. In particular, we are investigating generation mixes based on dispatchable generation technologies including nuclear and power CCS with such ones predominantly based on variable renewable energy and compare their total annual costs. The key interests of this modelling are the deployed capacity of power CCS technologies in these different versions of a future UK power system and their utilisation.

1.3 Report structure

The report is structured into the following sections:

Section 2 begins with a review of available CO_2 capture and storage technologies, examines the existing CO_2 capture facilities retrofitted to power plants, evaluates the future requirements on power CCS facilities and explains the approach taken for the techno-economic assessment of power CCS facilities.

Section 3 outlines the cost reductions available in power CCS facilities, detailing the opportunities that were taken forward for further examination following the stakeholder engagement sessions that were conducted.

Section 4 details the methodology used in the techno-economic assessment, presents the cost reduction potential identified through the assessment and introduces the sensitivities of the modelling to the assumptions made in the techno-economic assessment.

Section 5 provides details of the methodology used to model alternative versions of the UK power system and the role of power CCS in those.

2. Landscape mapping for power generation and CO_2 capture technologies for power generation

2.1 Overview of power CCS technologies

There are three basic categories of CO_2 capture technologies that could be used at power generation facilities: pre-combustion, oxy-fuel, and post-combustion approaches. Pre-combustion involves the gasification of coal or other fuels into a mixture of hydrogen and CO ('syngas'). Using a water-gas shift reaction, the CO is converted to CO_2 and more hydrogen; hydrogen can be used as a fuel in a turbine to produce electricity and CO_2 is separated out for storage. Oxy-fuel combustion processes burn the fuel in pure oxygen or a mixture of oxygen and recycled flue gas, producing an exhaust gas that is predominantly composed of CO_2 and water vapour. This reduces the energy requirements for CO_2 capture, as the gas is present in much larger concentrations than in typical combustion processes. Post-combustion processes separate CO_2 from the exhaust gases produced when combusting the fuel, e.g., using a solvent to capture the CO_2 present in the exhaust gas stream.

Post-combustion is the primary method proposed for use in existing power plants, as it is most suited to retrofitting, whilst pre-combustion CO_2 capture has been mainly proposed for use in non-power industrial processes, e.g., for steam-methane reforming used for hydrogen, methanol, or fertiliser production. Post-combustion capture technologies have already seen some commercial deployment, having been applied in the retrofitting of two power generation plants to date. Pre-combustion capture technologies have achieved commercial deployment, with commercially available technologies used by industrial facilities across the globe, such as the Enid Fertilizer facility in the US operational since 1982.[14] However, pre-combustion capture has still not been deployed at scale for power CCS. Finally, oxy-fuel combustion is being piloted at the Allam cycle plant developed by 8 Rivers and NET Power. A 50 MW pilot plant in La Porte, Texas, started operation in 2018 and in 2021 was synchronized with the state electrical grid, although it also remains to be deployed at commercial scales. Within each CO_2 capture technology grouping there are several different technologies proposed and/or used in its implementation, which are detailed in the rest of this section.

2.1.1 Pre-combustion capture

Coal Integrated Gasification Combined Cycle (IGCC)

An Integrated Gasification Combined Cycle (IGCC) uses a high-pressure gasifier to turn coal or other carbon-based fuels into high pressure syngas (a mixture of hydrogen and carbon monoxide, which can also contain some carbon dioxide and methane). This then passes through the water gas shift process which converts CO to CO_2, while creating additional hydrogen. The CO_2 is present at a high concentration, which can then be captured using physical, chemical or hybrid solvents and sent off for storage. The decarbonised syngas can then be used in a combined cycle gas turbine (adapted to run on hydrogen) to generate electricity. The gasification process however involves a considerable level of complexity and introduces a necessary gas cleaning step (e.g., to remove H_2S), as well as the need for air separation units and sizeable oxygen storage capacities, which pose challenges for this capture route. Pre-combustion capture also involves a long start-up procedure, including heating up the gasifier, the synthesis plant, and the air separation unit.

Due to the high pressure and high concentration of CO_2 in the gas stream, CO_2 removal in an IGCC requires considerably smaller and less complex process equipment than post-combustion CO_2 removal technologies. All process steps are commercially available and six coal-based IGCC plants exist world-wide (without CO_2 capture), some of which have been in operation for over a decade. However, the overall capital cost of the base gasification process can be expensive, exceeding conventional pulverized coal power plants, and there are limited numbers of IGCC gas plants worldwide that could be retrofitted with CO_2 capture technologies. Additionally, the operational complexities pose challenges to its implementation.

[14] Global CCS Institute, 2022. Global Status of CCS 2022.

Natural gas Integrated Reforming Combined Cycle (IRCC)

An Integrated Reforming Combined Cycle (IRCC) uses an auto-thermal reforming process to generate high pressure syngas by partially oxidizing a natural gas feed with oxygen and steam. Similar to the IGCC process, subsequent catalytic reforming then takes place, with the product stream of carbon monoxide converted into carbon dioxide and hydrogen in a water-gas shift reaction. Much like an IGCC, this process captures CO_2 from a much higher pressure and concentration stream than post-combustion CO_2 capture waste gases, using physical, chemical or hybrid solvents and transported for storage. The decarbonised syngas is then cleaned and burned in a gas turbine, with the hot exhaust gases used to generate steam to run a steam turbine. Similar to a coal IGCC with CCS, this cycle requires considerably smaller and less complex CO_2 capture process equipment than post-combustion CO_2 capture technologies. However, while the main components of the systems have all been demonstrated at full scale, the process arrangement of the IRCC scheme has not yet been demonstrated commercially.

2.1.2 Oxy-fuel combustion technologies

Oxy-coal combustion

In oxy-coal combustion, pulverised coal is burnt in pure oxygen or a mixture of oxygen and recirculated flue gas, instead of combustion taking place with air. This purer mixture burns at a higher temperature than natural air, which increases the efficiency of the combustion process. The gas mixture is also not diluted by the nitrogen present in air, making the flue gas stream smaller and easier to handle, with a higher concentration of carbon dioxide than in post-combustion. The carbon dioxide can then be captured more easily with a lower energy requirement than in post-combustion.

There are several pilot plants across the globe which have completed testing to evaluate the ability of the technology to scale up for commercial plants, including the Callide Oxy-fuel project in Queensland, Australia, the Vattenfall oxy-fuel plant in Germany and the CUIDEN plant in Spain. However, the primary disadvantages of oxy-coal combustion are the high energy requirements for extracting oxygen gases from the atmosphere at high purities, and the very high temperature produced in the combustion chamber because of the oxy-fuel combustion process.

Allam cycle

The Allam or Allam-Fetvedt cycle is a novel design for a natural gas power plant that could in theory capture close to 100% of its carbon emissions, whilst maintaining cost competitiveness with electricity produced from conventional natural gas NGCC plants. The Allam cycle achieves this through burning natural gas in pure oxygen, with the resulting high pressure and high temperature CO_2 gas produced from combustion being used as the working fluid and recycled through the combustor, turbine, heat exchanger and compressor within the power plant's systems to generate electricity. Most of the high-pressure CO_2 is reheated and returned to the combustor, whilst excess CO_2 is captured ready for storage.

The Allam cycle is attractive from a CO_2 capture perspective because not only does it offer a theoretical capture rate of 100% (excluding leakage), but it also achieves high rates of capture with a lower loss in energy conversion efficiency relative to a standard combined cycle gas turbine plant equipped with post-combustion CO_2 capture. As a result, CO_2 can be separated at a relatively low cost. The cost of purifying oxygen from the air using an air separation unit (ASU), however, increases the total cost of the technology.

The Allam cycle was developed by 8 Rivers and NET Power. Several commercial projects are under development. The 300 MW Whitetail project in the UK has been shortlisted under the Cluster Sequencing funding round provided by DESNZ.[15] NET Power and their partners are also working towards a FOAK project at an Occidental Petroleum site in Texas.[16] Two other commercial projects are currently under development:,

[15] https://www.gov.uk/government/publications/cluster-sequencing-phase-2-eligible-projects-power-ccus-hydrogen-and-icc/cluster-sequencing-phase-2-eligible-projects-power-ccus-hydrogen-and-icc
[16] https://www.powermag.com/net-powers-first-allam-cycle-300-mw-gas-fired-project-will-be-built-in-texas/

the 280 MW Broadwing project in Illinois, and the 280 MW Coyote project in Colorado, although there is still uncertainty regarding the progression of these projects.

2.1.3 Post-combustion capture

The variations in post-combustion capture technologies are mainly focused on the separation techniques used to capture CO_2 from the waste gas stream of the combustion chamber in a conventional power plant or fired heater. These separation techniques include sorbents, membranes, chemical solvents, and molten carbonate fuel cells. There are four separation mechanisms that can be leveraged to separate gases in the context of CO_2 capture; absorption, adsorption, diffusion, and phase change, with each of the technologies trying to take advantage of one of these mechanisms.

Solvents (amines)

Current commercially available technologies for post-combustion CO_2 capture normally use a liquid solvent, which chemically reacts with CO_2. The CO_2 is selectively removed from the exhaust gas and absorbed into the solvent at a given temperature and pressure. By changing the temperature and/or pressure of the CO_2 'rich' solvent, the CO_2 can then be liberated from the solvent, regenerating it for use again in continuous cycle, and piped away at high purity for storage or utilisation.

Alkylamine compounds (more commonly referred to as amines) have been used in industrial processes for over 60 years to remove hydrogen sulphide and CO_2 from gases, and so have attracted significant interest for use as a solvent for post-combustion CO_2 capture. A high proportion of the energy demand for post-combustion CO_2 capture is the thermal energy required for amine regeneration, which has motivated research into developing new amine solvents with a lower heat duty requirement. Companies such as Mitsubishi Heavy Industries (MHI), Shell Cansolv, Fluor, Carbon Clean and Aker Carbon Capture have all developed their own proprietary amine solvents for use in CO_2 capture facilities. However, for some amines such as 'tertiary' amines there is a trade-off between lower heat duty and the stability of the molecule, so these factors must be weighed up when selecting the liquid solvent for use in a CO_2 capture facility. The two commercial scale demonstrations of power CCS facilities, detailed later in this report, both used such amine-based CO_2 capture systems to strip the CO_2 from the flue gas.

Alternative solvents

Whilst amines are the main solvents used in the commercial post-combustion CO_2 capture facilities, they require a high energy input to separate dissolved CO_2 from its molecules and come with significant health risks due to the high toxicity of degradation products that could be carried over with the vented flue gas. Amines also degrade in the presence of O_2, NO_X, SO_2 and high temperatures, which can result in solvent loss across the lifetime of the CO_2 capture plant, increasing the overall cost of solvent makeup or reclaiming. Several other liquid solvents are currently under research and piloting and have been proposed for post-combustion CO_2 capture, including ammonia and salt-based solutions such as carbonates, hydroxides and amino acids. Recent commercial developments in liquid solvents have included ionic liquids developed by ION Clean Energy (although development of their ionic-liquid-based absorbent is no longer being progressed, with amine-based solutions progressed instead), a phase change solvent developed by IFP Energies Nouvelles and licensed by Axens, the carbonic anhydrase enzyme developed by Saipem, or the hot potassium carbon solvent capture system patented by CO_2 Capsol.

Physical solvents have also been proposed for use in post-combustion capture, such as Rectisol, Selexol or Fluor Solvent. However, physical solvents are normally more suited to pre-combustion CO_2 capture technologies. A higher CO_2 concentration is needed because the interaction between CO_2 and physical solvents is weaker than with chemical solvents. Also, in pre-combustion gas streams there is a larger physical contrast between the molecules being separated – i.e., there is a greater physical contrast between CO_2 and H_2 than between CO_2 and N_2.

Sorbents

Sorbents leverage the mechanism of adsorption for CO_2 capture. Adsorption is the mass transfer of molecules from a gas onto the surface of a solid or liquid phase. Sorbents include a range of porous, solid-phase materials such as mesoporous silica, zeolites, and metal-organic frameworks. Calcium looping, which uses calcium oxide as the sorbent, has also received promising results and is being considered as a potentially more efficient, less toxic alternative to amine-based systems.[17] Compared to solvents such as amines, solid sorbents can selectively adsorb CO_2 without a chemical reaction taking place. This means that separating the adsorbed CO_2 from the sorbent requires less energy to release the CO_2 from the sorbent's surface. Depending on how sorbents are regenerated, adsorptive separation can be divided into pressure swing adsorption (PSA), vacuum pressure swing adsorption (VPSA), or temperature swing adsorption (TSA). Larger capacities of CO_2 can be adsorbed for a given quantity of sorbent compared to amine-based solvents and it does not have the same issues with environmental impacts that amine-based solvents do.

However, manufacturing costs for sorbents are expected to be much higher than the cost of (simple) amine solvents. Flue gases also degrade sorbents, which could increase the cost of a sorbent-based system even further, and there are several engineering challenges (related to solids handling, heat transfer, and pressure gradients, among others) to be overcome before sorbent-based CO_2 capture systems are at the same Technology Readiness Level (TRL) as liquid-solvent based CO_2 capture systems.

Membranes

Membranes have also been proposed as a technology suited to capturing CO_2 from the flue gas stream in post-combustion CO_2 capture. They have been used for gas separation since the 1970s and operate through selectivity and permeability, allowing certain molecules through whilst preventing or slowing others. Polymeric membranes have been proposed for use in the capture of CO_2, due to the maturity of the technology across a variety of industries, including petrochemicals, whilst nano-porous membranes which have very small pore diameters are currently also under development for use in CO_2 capture.

Compared to other capture methods, membranes have advantages due to their small footprint, simpler setup, and increased ease of operation. Their energy requirements for separation are primarily in the form of electricity, rather than thermal energy as is the case in solvent-based systems. In the context of flexible power CCS operation, membrane technologies offer a higher ramping rate than amine-based absorption thanks to its low operating temperatures. As with other capture technologies, however, operating at low rates will reduce the efficiency of operation of pumps, blowers, and compressors. Membranes are especially dependent on CO_2 concentration levels, as the concentration gradient is a large driving force in the separation mechanism.

However, due to relatively low molecular fluxes through membranes and the higher cost of selective membranes, large scale membrane separation is lagging deployment compared to conventional approaches such as amine-based systems. Membranes also offer a much lower capture rate than other post-combustion technologies, unless more complex multi-stage configurations are used, with the most economical capture rate according to the leading developer, MTR, at a 50-60% capture rate.[18]

Molten Carbonate Fuel Cells (MCFC)

Molten Carbonate Fuel Cells (MCFCs) are high-temperature fuel cells that operate at temperatures of 600 °C or above, using molten carbonates as their electrolyte material. MCFCs can capture CO_2 from a power plant's flue gas whilst generating additional electricity by using carbon dioxide as a working fluid. The cell takes in CO_2 at low concentrations in the cathode inlet stream and combines it with oxygen and two electrons to form a carbonate ion, which carries the charge through the electrolyte to the anode. Here it reacts with hydrogen to

[17] Dean et al (2011). The calcium looping cycle for CO_2 capture from power generation, cement manufacture and hydrogen production. Chemical Engineering Research and Design 89 (6).

[18] MTR are one of the leading developers of membrane technologies for carbon capture. Their system is most economical at a CO_2 capture rate of 50-60%, though does offer capture rates of up to 90%: [Other Industrial Plants - Membrane Technology and Research (mtrinc.com)](mtrinc.com)

yield water, two electrons and CO_2, with the outlet gas typically comprising nearly 70% CO_2 alongside H_2 and water, which is a better mixture for CO_2 capture and storage.

This approach would capture up to 90% of the CO_2 whilst generating additional electricity instead of decreasing the plant's net power output, offering an attractive opportunity compared to other post-combustion technologies. However, the technology is currently at a TRL of 5 (Demonstration phase) and so is not as commercially ready as other CO_2 capture technologies such as amine-based liquid solvents. FuelCell Energy is one of the leading developers of molten carbonate fuel cells for use in CO_2 capture and has more than 100 US fuel-cell patents.

2.1.4 Selection of use cases for the techno-economic assessment

In the long term, most of the technologies listed above could potentially demonstrate merits to capture a significant share of power CCS deployment. For the present analysis, however, only options with a high near- and medium-term potential are included. Because of this, the most mature capture technology for each main fossil fuel generation technology, plus one promising emerging technology, were taken forward to be examined in the techno-economic assessment (TEA). The TEA will thus include:

- Natural gas NGCC with post-combustion capture
- Coal SCPC with post-combustion capture
- Oxy-fired supercritical power generation (Allam cycle)

For post-combustion capture the analysis was focused on amine-based capture. The Allam cycle was taken forward to the techno-economic assessment as it is more mature than other emerging technologies, with several commercial projects under development.

Whilst it is now understood that capture rates higher than 90% are feasible and can have a limited impact on costs, the 90% capture rate has been the baseline target for years and has been the focus of most studies to date.[19] As a result, there is greater data availability for such a capture rate and it constitutes the base case for the TEA. To incorporate the evolving drive towards higher capture rates, however, these were also modelled.

2.2 Large-scale commercial facilities

2.2.1 Petra Nova facility

Figure 1: Petra Nova Facility in Texas, US.[20]

The Petra Nova 240 MW coal-based power plant in Texas was retrofitted with a post-combustion CO_2 capture system in December 2016.[21] Figure 1 shows the capture plant for the Petra Nova facility. The project was owned by NRG Energy and JX Nippon Oil and had a target capture rate of over 90%, with the CO_2 captured using an amine-based absorption system supplied by MHI. It captured an estimated 1.6 million tonnes of CO_2 per year, with the captured CO_2 sent 82 miles away to the West Ranch oil field to be used for enhanced oil

[19] IEAGHG (2019) Towards zero emissions CCS with biomass or higher capture rates.
[20] https://www.power-eng.com/coal/petra-nova-an-evolutionary-project/;
[21] https://www.energy.gov/fecm/petra-nova-wa-parish-project

recovery (EOR). The retrofitted CO_2 capture system cost an estimated US$1bn, which was supported by a grant of US$195m from the US Department of Energy.

On the 1st of May 2020, NRG suspended operations at the Petra Nova CCS facility, citing the impacts of the worldwide economic downturn on the demand and price of oil.[22] It was placed in a reserve shutdown status to allow it to be brought back online when economic conditions improve. NRG has since sold its stake in the project for a mere $3.6m (<0.5% of the projects capital costs), [23] and JX Nippon has stated it anticipates bringing the Petra Nova CCS facility back online in 2023 after NRG finishes repairs on the coal-fired power unit to which it is connected.[24]

2.2.2 Boundary Dam 3

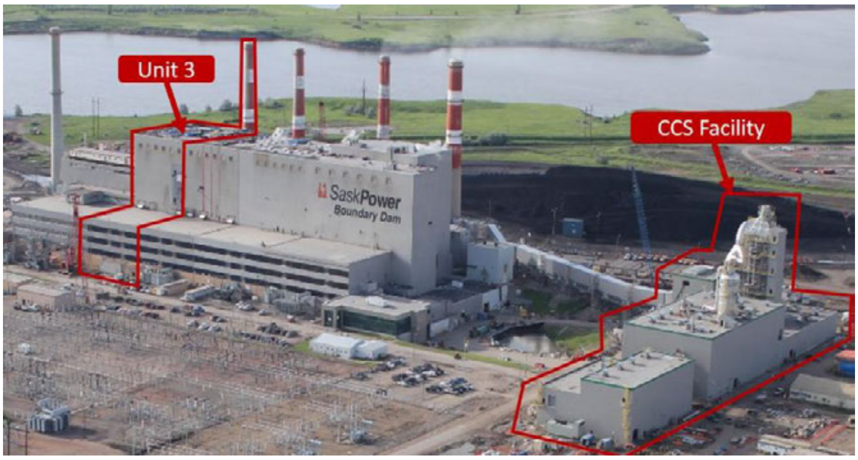


Figure 2: Boundary Dam 3 Facility in Saskatchewan, Canada.[25]

Unit 3 of the Boundary Dam coal-fired power station in Saskatchewan, Canada, was retrofitted with a post-combustion CO_2 capture and storage system in October 2014. This made the Boundary Dam station the first coal power station in the world to successfully use Carbon Capture and Storage technology. Figure 2 shows the capture plant for Boundary Dam 3. The project is owned by SaskPower and produces a net 115 MW of power, using the Cansolv process – an amine-based solvent system supplied by Shell. It has a target capture rate of up to 90% of the CO_2 present in the flue gases and aims to capture all of the SO_2 emissions produced during the combustion process. The capture plant was designed to capture 1 Mt CO_2 per year, and in 2020 it captured over 0.7Mt CO_2. Captured CO_2 is sent to the nearby Weyburn oil field to be used for EOR. The cost of the CO_2 capture system was estimated between $CAN1.3-1.5bn, of which it received $CAN240m in grants from the Canadian federal government.[26]

The facility reliability suffered from several issues. Among them were a higher-than-expected amine degradation and an underperforming thermal reclaimer unit, several leaking units, or shortcomings in the heat exchanger performance. Planned outages in 2015 and 2017 allowed to mitigate some of these shortcomings and, as shown in Figure 3, the plant availability increased significantly.

22 https://www.nrg.com/case-studies/petra-nova.html
23 https://ieefa.org/resources/ill-fated-petra-nova-ccs-project-nrg-energy-throws-towel
24 https://www.japantimes.co.jp/news/2023/02/09/business/carbon-capture-plant-second-chance
25 Giannaris et al, 2021. SaskPower's Boundary Dam Unit 3 Carbon Capture Facility – The Journey to Achieving Reliability.
26 Carbon Capture and Sequestration Technologies - MIT

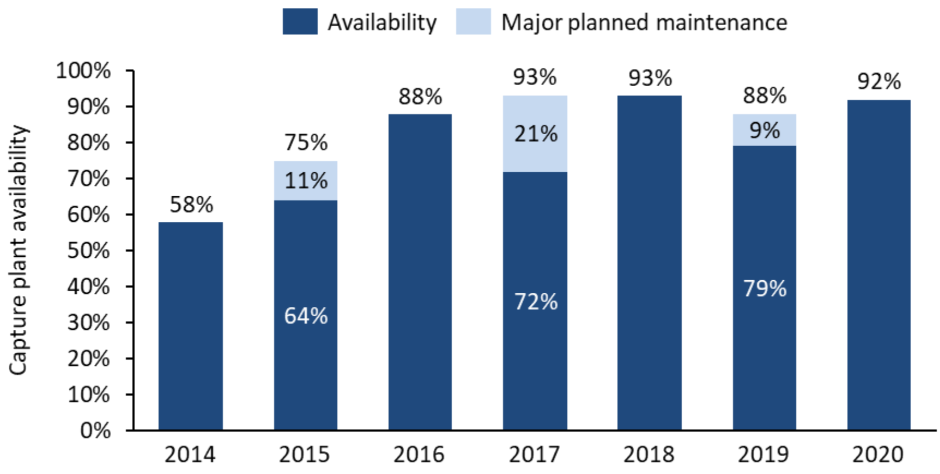


Figure 3: Annual availability of Boundary Dam 3 capture facility[27]

2.2.3 Shand feasibility study

In 2018, the International CO_2 capture and Storage Knowledge Centre conducted a feasibility study on the retrofit of SaskPower's Shand Power Station, which is a 300 MW single unit coal-fired power plant that would have double the capture capacity of Boundary Dam 3's CCS facility. The feasibility study was based on learnings from the actual design, construction, and operation of CCS technology at Boundary Dam 3 and detailed many improvements that could be made over the 'first-generation' deployment of CO_2 capture and storage at Boundary Dam 3.

Compared to the Boundary Dam 3 CCS facility, the CCS facility proposed for Shand Power Station could see reductions of up to 67% in capital costs per tonne of CO_2, as well as up to 92% in potential savings to power plant integration capital costs. The overall cost of capture was estimated at USD$45/t CO_2, with a capture rate of up to 97% when operating with reduced loads.[28] These cost reductions were realised from a doubling of the power plant scale, more effective integration of the CO_2 capture technology, simplifications, and other lessons learned. However, these reductions in capital and integration costs must be caveated by the fact that Boundary Dam 3 involved a life-extension of the existing generation asset and so had a much larger capital expenditure.

2.2.4 Lessons from the design and operation of the power CCS facilities

Both Petra Nova and Boundary Dam 3 faced frequent outages and operational challenges, as to be expected with the first two commercial-scale deployments of CO_2 capture facilities in the coal power generation sector. Operation of the plants revealed that challenges unrelated to the capture unit – such as compressor downtimes or leaking heat exchangers – can have a significant impact on the capture plant's availability. The Boundary Dam project also observed much higher rate of solvent degradation than expected. However, despite setbacks both projects demonstrated CO_2 capture technologies at scale with a 90% capture rate and suggested that there is potential for higher capture rates and more widespread use at lower costs.

The two facilities were designed for baseload operation of the power plants, which is the current mode of operation for coal fired power plants and is compatible with a low penetration of renewables onto the electricity grid. For a future electricity grid with a high penetration of variable renewable energy sources (VREs), it is likely that dispatchable generators will need to play a greater role providing balancing services. Power stations equipped with CO_2 capture and storage facilities will also need to offer increased flexibility, and the baseload model may no longer be feasible in the future. Accordingly, the proposed design in the Shand feasibility study could have the capability of turning its power output to as low as 62% of the rated capacity, offering increased flexibility relative to solely baseload operation.[29]

[27] Adapted from Giannaris et al, 2021.
[28] International CCS Knowledge Centre, 2018. The Shand CCS Feasibility Study Public Report.
[29] Ibid.

Despite operational drawbacks and the mothballing of Petra Nova, both projects have offered significant learnings for the future deployment of power CCS. The developers behind both projects have claimed that, following their experiences, they could find significant cost reductions in future CO_2 capture and storage retrofits to coal-fired power stations. Shand could offer a 67% capital cost reduction compared to the Boundary Dam 3 facility, achieving a capture cost as low as $45/t CO_2,[30] whilst MHI has claimed that their updated technology and lessons learned from Petra Nova can lead to a capital cost reduction of nearly 30% for the next large-scale plant.[31] Both Shell (the supplier of Boundary Dam 3's CO_2 capture technology) and MHI have improved the solvents used to capture carbon dioxide based on the long-term testing available at these facilities. Newer solvents proposed by MHI and Shell for their CO_2 capture technologies mainly offer improved stability and reduced degradation compared to the solvents used at the power stations. For instance, the KS-21 solvent has 50% lower amine emissions compared to KS-1 (the solvent used at Petra Nova) with a comparable energy performance.[32]

2.3 Future demands on power CCS facilities

CCS technologies will play an important role in reaching net zero targets. The operating mode of power CCS plants will depend heavily on the sections of the electricity markets that they operate in, but for power CCS to be scaled and avoid the risk of stranded assets, the technologies will likely need to be compatible with high levels of generation flexibility. Plants operating in the wholesale market will need to be able to respond flexibly to market conditions, for example as the penetration of variable renewable energy sources in the wholesale market increases.[33]

To ensure that power CCS is designed for flexible generation, three design principles must be followed. These are a minimisation of CAPEX, pursuit of revenue opportunities in additional markets, and integration of thermal/solvent storage with the capture plant. The levelized cost of electricity (LCOE) is more sensitive to the CAPEX values at low capacity factors, so a certain efficiency loss might need to be accepted as a trade off when minimising the CAPEX for the power CCS facility. The contribution of the capital cost to the LCOE increases when the capacity factor decreases, because the total fixed cost needs to be spread out over fewer operating hours. At the same time, plants with a higher efficiency usually present higher unit CAPEX than those with a lower one. A higher efficiency allows plants to reduce their fuel costs and hence carbon footprint per unit of electricity generated. When the capacity factor drops and CAPEX becomes a dominant cost component, minimising the CAPEX may be more important than reducing fuel costs, and hence plants with a lower efficiency may become attractive. Providing other grid services beyond baseload generation can create additional value propositions, although for some ancillary services such as frequency response other low carbon technologies such as batteries are expected to perform much better. Finally, storage solutions to increase the capture plant flexibility will need to be very low in capital, and alternatives to integrating storage might result in lower cumulative capture rates.

2.4 Estimation of costs of power CCS facilities

2.4.1 Approach taken for cost estimates in this study

Cost estimates and breakdown for power CCS technologies were taken from publicly available studies that offer bottom-up cost estimates of new projects on greenfield sites. Several studies provide detailed bottom-up cost estimates, with clear assumptions and well-defined boundaries. Some of these have built on data provided by CO_2 capture technology providers. The ability to extract and extrapolate their costs justifies their use in this study, although the accuracy of cost estimates taken from these sources might be lower than real world data from existing projects or FEED studies. On the contrary, cost data from existing and proposed power CCS facilities is hard to extrapolate, as few power CCS projects have published detailed cost breakdowns. For

[30] Ibid.
[31] Tanaka et, 2018. Advanced KM CDR process using new solvent.
[32] Ibid.
[33] It should be noted that power CCS facilities with revenues from EOR receive the competing incentive of producing a constant CO_2 stream. Hence, they may choose to operate with a different profile to increase predictable returns.

retrofit projects it is also hard to allocate costs between the host plant and the capture plant, as some projects, such as Boundary Dam 3, involve major upgrades to the host plant to extend its lifetime or increase its capacity. In the case of new-build projects, the boundaries often differ which hampers comparison. For instance, for the Allam cycle the air separation unit represents a large component of the total capital cost. However, the feasibility study for the Whitetail project does not include the air separation unit and an over the fence supply of oxygen is assumed instead.[34]

Three main sources of bottom-up data were identified through the literature review to be fed into the techno-economic assessment: Wood's report for BEIS in 2018 on next generation capture technologies,[35] the IEAGHG's benchmarks from 2020,[36] and the U.S. Department of Energy's National Energy Technology Laboratory (NETL) Cost and Performance Baseline for Fossil Energy Plants.[37] These three were selected as they provide detailed cost estimates with clear identification of assumptions, bottom-up cost modelling and multiple generation technologies both with and without CO_2 capture. Whilst all three studies assume a 90% capture rate as the reference case, the IEAGHG benchmarks also include higher capture rates. Moreover, further evaluation of high capture rates is available from the IEAGHG's Towards Zero Emissions CCS in Power Plants[38] and NETL's technical note on capture cases with a capture rate greater than 90%.[39] The most recent version of NETL's Cost and Performance Baseline also now includes higher capture rates above 95%.[40] Results from this version are not included in the present report.

Out of the three studies only BEIS' covers bio-energy with CO_2 capture and storage (BECCS). This study was complemented with the previously mentioned IEAGHG's Towards Zero Emissions study and NETL's baseline on BECCS techno-economics.[41]

2.4.2 Selection of data to use in the techno-economic assessment

The key assumptions and values used in the calculations for these three studies are included in the table below. As well as the bottom-up approach to cost estimation, there are several key similarities in the assumptions made in each of the studies. Table 1 shows a comparison between the three sources and the main assumptions. All assume the same capture system (Shell Cansolv), they include CO_2 compression to a similar specification, exclude the transport and storage costs, and use comparable efficiency values in calculations.

Table 1: Comparison between BEIS', IEAGHG's, and NETL's cost benchmark studies.

		Wood for BEIS	IEAGHG 2020-07	NETL
	Currency base	Q12017 £	3Q2018 €	Dec2018 U$D
	CAPEX[42]	TCR	TCR	TOC
	Costs	NOAK	Not mentioned explicitly; assumptions seem NOAK	NOAK
	Interest during construction	Yes	Yes	No (TASC also available)
	Contingencies	No	10% of installed cost	17% of installed cost
SCPC	Net power output (MW)	814.2	825.9	650
	Efficiency (LHV)	34.7%	35.4%	32.7%
	Capture rate	90%	90%	90%
	Capacity factor	90%	90%	85%

[34] 8 Rivers, 2021. Project Whitetail Report Final. Carbon Capture Utilisation and Storage (CCUS) Innovation Programme.
[35] Assessing the Cost Reduction Potential and Competitiveness of Novel (next Generation) UK Carbon Capture Technology, Wood, October 2018
[36] Update Technoeconomic Benchmarks for Fossil Fuel-Fired Power Plants with CO_2 Capture, IEAGHG, TR 2020-07, July 2020
[37] Cost and Performance Baseline for Fossil Energy Plants Volume 1, Revision 4, US Department of Energy. September 2019.
[38] Towards zero emissions CCS in power plants using higher capture rates or biomass, IEAGHG, TR 2019-02, March 2019.
[39] Bituminous coal and natural gas to electricity: >90% capture cases technical note, NETL, 2021.
[40] Cost and Performance Baseline for Fossil Energy Plants Volume 1, Revision 4a, US Department of Energy. October 2022.
[41] Technoeconomic and Life Cycle Analysis of Bio-Energy with Carbon Capture and Storage (BECCS) Baseline, NETL, 2021.
[42] TCR: total capital requirement; TOC: total overnight costs; TASC: total as-spent capital

		Wood for BEIS	IEAGHG 2020-07	NETL
	Steam condition	27MPa/600°C/620°C	27MPa/600°C/620°C	24.1MPa/593°C/ 593°C
	Fuel	Bituminous coal	Bituminous coal	Bituminous coal
	Fuel price[43]	Variable, $1.36-$2.72/GJ	€2.5/GJ	$2.19/GJ
	Solvent	Cansolv DC-103	Cansolv	Cansolv
	CO_2 compression configuration	5 stages in parallel trains 110 bar, 30°C	5 stages in parallel trains 110 bar, 30°C	8 stages in parallel trains 153 bar, 30°C
	Pre-treatment[44]	Wet FGD with limestone; low-NOx burners and SCR	Wet FGD with limestone; SCR	Wet FGD with limestone; low-NOx burners and SCR
NGCC	Net power output (MW)	1064.6	1344.2	646
	Efficiency (LHV)	52%	55.6%	52.8%
	Capture rate	90.8%	90%	90%
	Capacity factor	90%	93%	85%
	Power configuration	2 x (H-class turbine + ST)	2 H-class turbines + 1 ST	2 x (F-class turbine + ST)
	Fuel price[43]	Variable, £2.99-£5.76/GJ	€6/GJ	$4.19/GJ
	Solvent	Cansolv DC-201	Cansolv DC-201	Cansolv
	CO_2 compression configuration	5 stages in parallel trains 110 bar, 30°C	7 stages + pump in parallel trains 110 bar, 30°C	8 stages in parallel trains 153 bar, 30°C
	Pre-treatment	None	SCR for NOx	SCR and low NOx burners

Despite the similar approaches and assumptions taken for cost estimation, there is a large variation in cost components between these three sources and the IEAGHGs Towards Zero Emissions report from 2019. The variations in cost components are presented in Figure 4, which compares the normalised CAPEX, fixed OPEX, and variable OPEX values calculated in each of the studies across different generation technologies and normalised to the relevant functional unit.

There are several key drivers of differences across the CAPEX and OPEX normalised values in the three studies. The CAPEX values are impacted by the size of the plant (with large differences for combined cycle gas turbines (CCGT) power plants) and whether capital contingencies – funds added to the cost estimate to account for uncertain additional costs – are included or not. In the case of fixed OPEX, the main differences across the studies are due to the assumed labour costs, whilst annual operation and maintenance costs are expressed as a percentage of CAPEX with similar values used across studies. The variable OPEX definition also differs across the three studies, with the IEAGHG study's definition including only consumables, whereas the other studies also include replacement of equipment and maintenance material in the variable OPEX costs. Biomass co-firing in SCPC power plants with CCS shows substantial differences between the NETL and the IEAGHG studies. The IEAGHG Towards Zero Emissions report, that does not include efficiency drops because of co-firing, presents significantly lower costs. This IEAGHG report also presents significantly lower capital costs for high capture rates. Because its assumptions and cost breakdown are not as detailed as in the other studies, cost metrics from this report were not taken forward for analysis.

[43] Fuel price expressed per GJ LHV
[44] FGD: flue gas desulphurisation; SCR: selective catalytic reduction

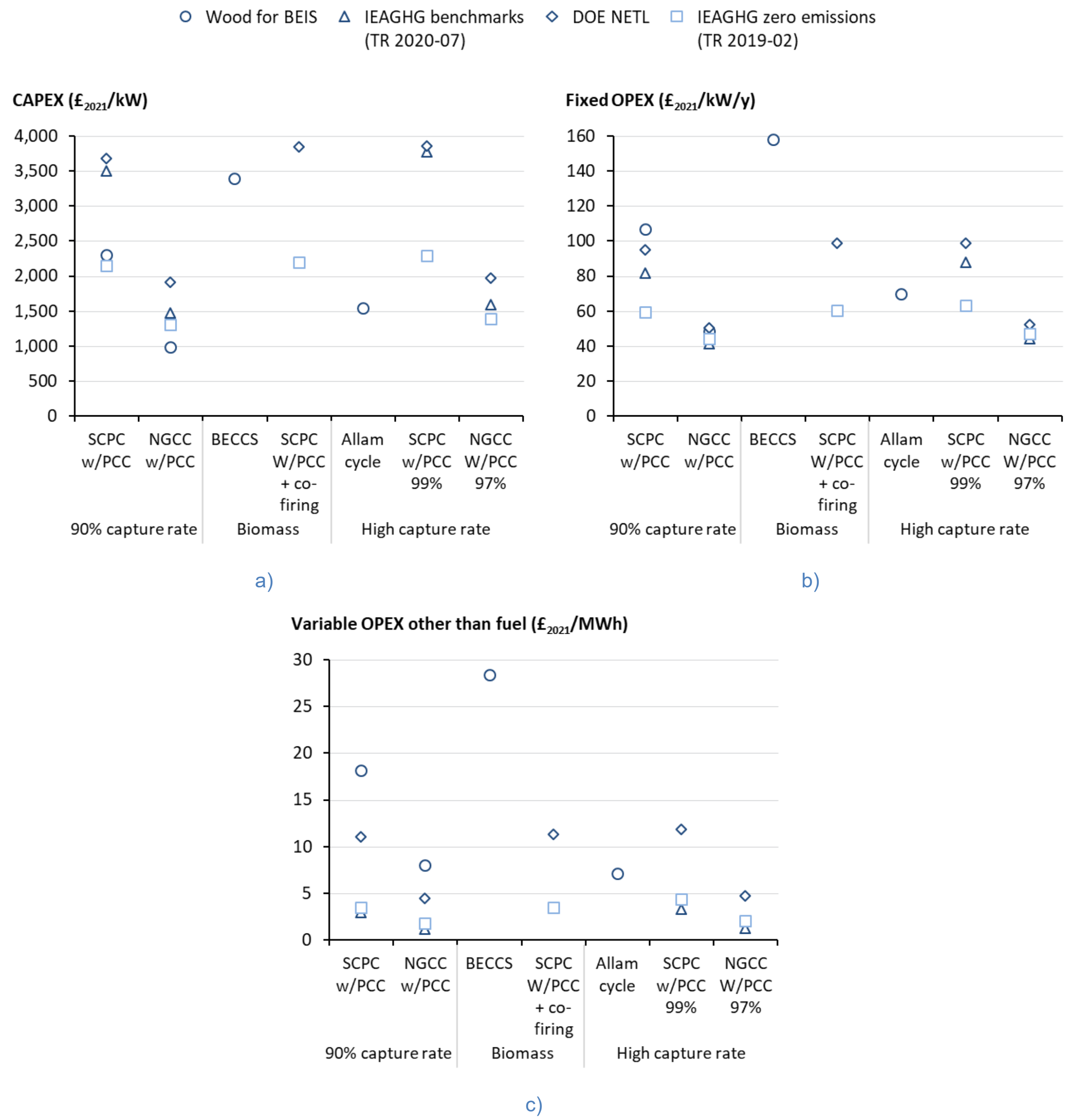


Figure 4: Cost components for different power CCS technologies from the different benchmark studies

Following evaluation of the results of these studies, a key reference for each generation technology was selected. Selecting one of the reviewed studies for each power technology is more methodologically transparent than averaging the reviewed values, and the use of the same reference for every case within a power group was prioritised. Table 2 shows the cost metrics carried forward for the techno-economic analysis. The IEAGHG benchmarks were selected for natural gas combined cycle (NGCC) power plants, as the CAPEX values are representative of all reviewed studies, and whilst the OPEX values are at the lower end of the reviewed studies, the main driver of the LCOE will be the CAPEX values (particularly at low load factors). The NETL benchmarks were selected for SCPC power plants as the CAPEX and OPEX values are very similar to the IEAGHG benchmarks, and it includes all the coal plant generation cases that this study examines. The NETL and the IEAGHG's studies did not examine BECCS or the Allam Cycle, so the Wood study for BEIS was selected as the key reference for these generation cases.

It should be noted that Wood's study introduces a correction factor for the efficiencies to account for turbine degradation in performance. A degradation profile is used to correct the as-new efficiency and get an average efficiency. Wood uses two different degradation profiles: for gas turbines a lifetime average correction factor of 94.8% is introduced, whilst for coal-fired generation they assume a correction factor of 99.5%. The IEAGHG benchmarks and the NETL baseline, on the other hand, do not account for performance degradation over the lifetime of the assets. To ensure consistency between results, Wood's correction factors are used to adjust the efficiencies from the IEAGHG benchmarks and the NETL baseline.

Table 2: Reference study and cost metrics for each thermal generation technology.

Technology	Reference	CAPEX (£/kW)	Fixed OPEX (£/kW/y)	Variable OPEX (£/MWh)	Net power output (MW)	Fuel efficiency (LHV)[45]	Capture rate	Share of biomass (% of energy input)
NGCC w/o PCC	IEAGHG benchmarks	746	21.3	0.50	1,506	59.0%	-	0%
SCPC w/o PCC	NETL	2,037	55.6	6.09	650	41.6%	-	0%
NGCC w/ PCC	IEAGHG benchmarks	1,470	41.0	1.13	1,344	52.7%	90%	0%
SCPC w/ PCC	NETL	3,668	94.7	11.04	650	32.5%	90%	0%
SCPC w/ PCC + biomass co-firing	NETL	3,834	98.4	11.23	650	31.8%	90%	8.1%
BECCS	BEIS	3,392	157.7	28.31	396	30.6%	90%	100%
Allam cycle	BEIS	1,541	69.8	7.05	848	52.3%	90%	0%
SCPC w/ PCC 99%	NETL	3,844	98.7	11.83	650	30.9%	99%	0%
NGCC w/ PCC 98.5%	IEAGHG benchmarks	1,583	44.1	1.25	1,316	51.6%	98.5%	0%

3. Overview of cost reduction innovations

A longlist of cost reduction opportunities for power CCS was developed for this study, drawing from sources in the literature as well as project expert input. Cost reduction opportunities identified by the International CCS Knowledge Centre were a key input for this study.[46] Table 3 shows the opportunities that were considered for this study with a brief description.[47]

Table 3: Description of cost reduction opportunities.

Cost reduction opportunity	Category
Scaling up the CCS plant	Larger facilities can show lower unit capture costs with economies of scale as a driver.
Site layout and modularisation	Modular construction for large infrastructure projects can increase productivity and reduce costs. Proximity between the capture plant and the power unit can reduce integration costs.

[45] Average fuel efficiencies extrapolated from Wood report for BEIS, not provided for the IEAGHG benchmark or the NETL baseline studies.
[46] International CCS Knowledge Centre, 2019. Learning by doing: The cost reduction potential for CCUS at coal-fired power plants.
[47] While this study highlights cost reduction opportunities, it should also be noted that CCS unit CAPEX estimates over the last 18 months are severely impacted by current global economics. Large inflation in the price (and availability) of steel, gas, coal and knock-on impact on labour costs may make building a plant at present higher than if construction started 3 years ago.

Cost reduction opportunity	Category
Increasing capture rate	Increasing the capture rate beyond 90% can improve costs up to a tipping point.[48]
Increased efficiency of the host power unit	A more efficient host unit directly impacts the required size of the capture plant and the parasitic power losses.
Optimising the CCS operating envelope	Capture plants can be designed to have high availability but partially curtail CO_2 capture when outside a range of operating conditions. The advantage from capital cost savings from a narrower range of operating conditions can outweigh the limited impact on annual capture.
Development of a CCS supply chain	A well-developed supply chain can reduce technology costs, increase competition, reduce delivery times and reduce schedule risk.
Optimising the mass transfer process	Improved mass transfer of CO_2 from the flue gas to the solvent in the absorption column can decrease the column size, the largest item in the capture plant.
Construction materials	CO_2 in the presence of water can be corrosive to carbon steel, with stainless steel often specified for pipes, packed beds, heat exchangers or other components. Lower cost and less conservative design can use 304L rather than 316L stainless steel, low-carbon steel or even plastics for some components.
Capture plant de-risking	As more capture plants are built and confidence in the technology increases, 'learning through doing' can reduce project contingencies and the cost of capital.
Co-siting with electrolysers	For oxy-combustion technologies the air separation unit (ASU) to produce oxygen is a major capital cost component. Electrolytic hydrogen generation gives oxygen as a by-product. As hydrogen generation scales up, co-siting Allam cycle power plants with electrolysers can reduce the ASU's required capacity.
Amine degradation	Improvements to solvent stability and to amine reclaiming can drive costs down.
Maintenance costs	Redundancies at key pieces of equipment can reduce outages and unplanned maintenance, reducing the total operating cost.
Flue gas recirculation[49]	The flue gas from NGCCs has a low CO_2 concentration and high O_2 content. Recirculating the exhaust gas can lead to a higher CO_2 and lower O_2 content, decreasing the power losses for regenerating the solvent and the size of the absorber column.
Optimising thermal energy	Extracting steam from the existing power plant can be more economic and more thermally efficient than using auxiliary steam boilers. The energy requirements from the capture plant however impact on the host power unit output. Improved heat exchangers and solvents can reduce the energy cost.
Water consumption	Water from flue gas condensation can be reused to help meet the cooling requirements, decreasing treatment and disposal costs of wastewater. This opportunity is of relevance for plants burning high-moisture fuels such as biomass.

[48] IEAGHG, 2019. Towards zero emissions CCS in power plants using higher capture rates or biomass. TR 2019-02.
[49] Flue gas recirculation is also referred to as Exhaust Gas Recycling (EGR).

Cost reduction opportunity	Category
High pressure regeneration	High pressure solvent regeneration can reduce the reboiler duty (and the associated steam consumption) and the CO_2 compression cost. It can also lead to CAPEX cost reductions as the regenerator column diameter and height and the condenser area are reduced. This option was recently investigated for the Cansolv process. The findings suggest a 10% reduction in the reboiler duty and 20% reduction in CO_2 compression costs.[50]
Compression efficiency	Whilst compressor technology is already highly efficient, best efficiency is achieved at full load and there is limited ability to work at lower flows. Improvements can help to maintain efficiency when load following. Switching the final compression stage for a supercritical CO_2 pump can reduce the total power required to achieve high final export pressures.
Digitalisation	Analytical modelling and digital data could increase productivity, help achieve greater efficiencies, and reduce costs. Online monitoring of solvent performance also allows solvent maintenance to be optimised increasing solvent life, minimising emissions and maximising effectiveness.

Engagement sessions with stakeholders working across the power CCS value chain, including utilities, technology developers, and EPC contractors, were conducted to identify the cost reduction opportunities that hold the greatest potential. Additionally, opportunities were assigned to either technology developers or EPC contractors and utilities. The prioritised opportunities, covered in more detail in the following sections, are shown in bold in Table 4. Whilst there are multiple trade-offs between different cost reduction strategies, and the distinction on who is involved in which opportunity is not clear cut, the framework provides an initial overview of areas that might lead to improvements in the economics of power CCS.

[50] Stephenne et al., 2022. Recent Improvements and Cost Reduction in the CANSOLV CO2 Capture Process. Proceedings of the 16th Greenhouse Gas Control Technologies Conference (GHGT-16).

Table 4: List of cost reduction opportunities.

Cost reduction opportunity	Category	EPC contractors and utilities	Technology providers
Scaling up the CCS plant	**CAPEX**	**X**	
Site layout and modularisation	**CAPEX**	**X**	**X**
Increasing capture rate	CAPEX	X	X
Increased efficiency of the host power unit	CAPEX	X	
Optimising the CCS operating envelope	CAPEX	X	
Development of a CCS supply chain	**CAPEX**	**X**	**X**
Optimising the mass transfer process	CAPEX		X
Construction materials	CAPEX	X	X
Capture plant de-risking	**CAPEX**	**X**	
Co-siting with electrolysers	CAPEX	X	
Flue gas recirculation	**CAPEX & OPEX**	**X**	
Amine degradation	**OPEX**		**X**
Maintenance costs	**OPEX**	**X**	**X**
Optimising thermal energy	**OPEX**	**X**	**X**
Water consumption	OPEX	X	X
High pressure regeneration	OPEX	X	X
Compression efficiency	OPEX	X	
Digitalisation	OPEX		X

3.1 CAPEX reductions

CAPEX reductions are particularly important for cost-effective power CCS facilities, as it is anticipated that future operation may be at lower-than-baseload load factors to support the higher penetration of variable renewable energy. At low load factors, the CAPEX is spread across a reduced number of operating hours, and hence the CAPEX share in the LCOE increases. Measures that target reductions in CAPEX are therefore very important to improve the economics of future CCS installations deployed in the power sector.

CAPEX reduction opportunities initially considered for this study were:

- Scaling up of the CCS plant
- Site layout and modularisation
- Increases in CO_2 capture rate
- Increased efficiency of the host power unit

- Optimisation of the CCS operating envelope
- Development of a CCS supply chain
- Optimisation of the mass transfer process
- Improved construction materials
- De-risking of the capture plant
- Co-siting with electrolysers
- Flue gas recirculation

Scale-up of the CCS plant, site layout and modularisation, development of a CCS supply chain, flue gas recirculation, and capture plant de-risking were selected for further examination in this study following stakeholder engagement.

3.1.1 Scaling up the CCS plant

Economies of scale are non-linear relationships between unit costs and production capacities, with increased cost advantages at larger scales of operation. In heavy industries and power generation economies of scale are fundamental drivers, with larger plants offering increased economic efficiencies and cost savings compared to their smaller counterparts. Scaling up CCS facilities will offer increased CO_2 capture capacities relative to the cost of the facilities, resulting in a reduced contribution of CAPEX to the overall cost and so reducing the cost of abated power. Whilst Boundary Dam 3 and Petra Nova have capacities of 115 MWe and 240 MWe, the host power plants are much larger: Boundary Dam has a nameplate capacity of 531 MW and Petra Nova captures CO_2 from a slipstream of the WA Parish Station, with a nameplate capacity of 3.65 GW. Similarly, many coal- and natural gas-fired power plants are rated at much higher outputs than those addressed by the Boundary Dam 3 and Petra Nova capture plants. However, the scale of the host power plant is not a variable controlled by EPC contractors or technology developers. Instead, it is an initial condition from the project selection and is especially relevant for developers of new integrated power with CCS projects determining the most cost-effective scale of their plant.

3.1.2 Site layout and modularisation

Site layout was identified as an area that can strongly impact capital costs but over which different actors have limited to no control. For retrofit projects densely developed sites can complicate the siting of capture plants and increase costs. Modularisation, on the other hand, offers cost reduction opportunities for EPC contractors and technology providers alike. It should be noted that there are significant differences between modularised construction, a modular design of capture plants, and the standardisation of capture plants.

Modularised construction offers the largest cost reduction opportunities for power CCS among the three. It involves building sections of the plant off-site, transporting them as pre-assembled blocks and connecting them together on-site. Developers are working on modularised construction for large components such as absorber columns. As these units are typically too large to be transported if completely manufactured off-site, such an approach relies on shop fabricating sub-modules with a transportable size, with only module assembly needed at the site. Other units such as pipe racks, heat exchangers and pumps can also be fabricated as skids in fabrication shops. Modularised construction can result in shorter construction times, greater schedule surety, can provide access to lower-cost labour, and can improve fabrication quality and productivity. Nevertheless, its applicability depends on site-specific conditions such as constraints on transport routes to site and site logistics. Sites close to a harbour with good sea access and high local labour costs will benefit more from the approach.

Applying modular design and standardised capture plants to the total project is less relevant for large-scale power CCS which tend to be very large compared to many industrial applications. Use of multiple, smaller, fully modular parallel capture trains, would result in a loss of economies of scale and a larger plot space footprint. In some cases, if a design with one absorber column would result in an overly large column that presents engineering and constructive challenges, two parallel absorber columns could be an attractive option to limit their size – but this would not be a modular plant.

The standardisation of capture plants is the use of similar designs and components across different sites. This holds potential for smaller emitters, but large power plants currently require a bespoke design to optimise the process and achieve the lowest overall cost of plant ownership.

3.1.3 Development of a CCS supply chain

Well-established supply chains minimise CAPEX costs by promoting competition and prioritising innovation to reduce the costs of essential materials and technologies. The development of a competitive CCS supply chain would reduce the costs of the materials and technologies used in CCS facilities, bringing down the costs of CCS and supporting its widespread adoption. Additionally, a competitive CCS supply chain can lead to reduced delivery delays and lower risks of non-compliance to specifications, which would reduce project costs. Currently, there are few commercial facilities in operation, so the CCS supply chain needs further development to provide the conditions for cost reductions in technologies and input materials. Development of a well-established CCS supply chain will depend upon a favourable market for CO_2 capture being established, as this will ensure that suppliers and investors can have confidence in the future uptake of CCS projects across industries.

3.1.4 Flue gas recirculation

Flue gas recirculation can be an effective option to reduce capture costs for NGCC power plants. CO_2 post-combustion capture in NGCC power plants is challenged by the large flow of flue gas with a low CO_2 concentration, ranging from 3 mol% to 5 mol%. As a result, larger capture units with very large absorption columns are needed for the same CO_2 volume being captured when compared with coal-fired power generation. Recirculation of around 50% of the exhaust gas to the turbine inlet leads to a higher CO_2 content, that can reach 8 mol%.[51] Additionally, it lowers the O_2 content (and hence the oxidative degradation of the solvent) and the need for flue gas to be pre-treated. Despite a higher integration cost due to additional ducting, flue gas blower, and larger DCC to recirculate the flue gases, it can lead to substantial CAPEX and OPEX savings for the capture unit. A significantly smaller absorption column can be installed, and OPEX savings are achieved because the enriched flue gas requires lower solvent circulation, lower solvent inventory, and a lower energy penalty for regeneration. This option was highlighted both by EPC contractors and by technology providers as being highly relevant.

3.1.5 Capture plant de-risking

De-risking refers to the reduction or sharing of potential risks associated with an investment. Increasing the deployment of power CCS can lead to higher levels of confidence in the technology from investors and public bodies. As a result, lower project contingencies and access to capital at a lower cost can decrease the CAPEX. De-risking can also involve support from public entities, bearing a share of the risk of a private investor. Multiple stakeholders have agreed on the importance of de-risking investments on power CCS as a driver to lower CAPEX. Alternatively, process verification and certification by third parties is also a good way to build assurance that the capture plant will operate as designed and thus reduce the cost burden of perceived risks from less proven technologies.

3.2 OPEX reductions

At high utilisation rate, the OPEX contributes significantly towards the overall cost of a CCS facility. Most of this is related to the thermal energy and steam generation requirements to separate the CO_2 from the flue gases (in the case of post-combustion) or the process gases (in the case of pre-combustion or oxy-fuel approaches).

OPEX reduction opportunities initially considered for this study were:

- Amine degradation

[51] Li et al, 2011. Impacts of exhaust gas recycling (EGR) on the natural gas combined cycle integrated with chemical absorption CO_2 capture technology.

- Maintenance costs
- Optimisation of heat integration
- Water consumption
- Compression efficiency
- Digitalisation

Amine degradation, maintenance costs and optimisation of heat integration were selected for further examination following stakeholder engagement.

3.2.1 Amine degradation

Commercial CCS facilities predominantly use amine solvents in post-combustion CO_2 capture, which selectively binds to CO_2 at cold temperatures. The CO_2 can then be released from the 'rich' solvent through the application of heat. The solvent is continually circulated through the system, capturing CO_2 from the flue gas, and releasing the captured CO_2 in a theoretical closed cycle. However, the amine molecules degrade somewhat in contact with oxygen and flue gas impurities such as SOx and NOx, which reduces the capture efficiency and increases the OPEX by requiring solvent reclamation or extraction and replacement with fresh solvent. The costs associated with degradation of the amine molecules have a significant impact, and technology providers are currently focusing their efforts on reducing the impact of amine degradation on the overall operating costs of the system through development of alternative solvents and improved solvent maintenance equipment and operational practises. Lessons learned from Petra Nova and Boundary Dam 3 have already led to the development of more stable solvents from MHI and Shell Cansolv.

3.2.2 Maintenance costs

Maintenance costs were not factored into first-generation CCS facilities, due to their novel nature and the lack of operational experience with CCS facilities during construction and planning. Developing a better understanding of the maintenance requirements will help to reduce maintenance costs by avoiding the need for unplanned or emergency maintenance work. This would reduce the need for an unplanned shutdown of the plant, which carries a cost that is order of magnitudes higher than the cost of planned maintenance. An improved understanding of the impact of maintenance on the design and operating costs based on actual operation will allow maintenance costs to be kept under close control through forward planning. Additionally, including redundancies of key pieces of equipment can reduce outage duration, reducing the total operating cost. However, reducing maintenance costs by including additional redundancies presents trade-offs with the CAPEX. In effect, MHI has reduced the redundancy of their KM CDR process to decrease equipment CAPEX.[52]

3.2.3 Optimisation of heat integration

A high proportion of the OPEX of a post-combustion CO_2 capture plant is the thermal energy required to strip the CO_2 from the 'rich' CO_2-loaded solvent. Minimising the energy costs to satisfy the thermal energy requirements will therefore substantially reduce the OPEX for a CCS facility, with a considerable amount of research and technological development aimed at bringing down the energy requirements. This can be achieved by modification of the liquid solvent, or by more closely integrating the CO_2 capture facility with the host power plant, using any waste heat produced from the power cycle to strip CO_2 from the solvent. This opportunity, however, presents trade-offs between CAPEX and OPEX. Improved heat integration, with heat recovery from the steam turbine, the direct contact cooler (DCC) and the heat exchangers, can result in an increased CAPEX. The optimum selection of heating and cooling media, done on a site-by-site basis, can also reduce the energy costs.

[52] Tanaka et al, 2018. Advanced KM CDR process using new solvent.

4. A techno-economic analysis and business implications for a range of CCS options

In this chapter we explore the impact of the cost reductions for power CCS described in the previous chapter on the levelized cost of electricity of power CCS and its competitiveness compared to other dispatchable generation technologies. The chapter describes the approach of the techno-economic analysis as well as implications of the results on the business case for a range of CCS options.

4.1 Modelling approach

We have modelled the levelized cost of electricity (LCOE) for various dispatchable electricity generation technologies to identify which energy generation will provide the best value as its load factor increases. The LCOE is used to compare electricity generation and cost breakdown for different power generation technologies. This comparison can then be used to determine the lowest cost technology for each load factor range. This technoeconomic analysis draws on the costs identified in the literature review and stakeholder engagement from Section 3. The cost variables include the annualised CAPEX of the generation type, the fixed and variable OPEX, the fuel costs, carbon costs, and transport & storage costs of post-combustion captured CO_2. Additionally, we considered other relevant inputs including the pre-development (which covers completing technical and financial studies, planning the project, obtaining permits and licencing and completing due diligence[53]) and construction time of different generation types, generation efficiency, lifetime of the generation type, the capture rate of post-combustion CO_2, and the absorption rate of CO_2 should the generation type be a net carbon negative process (e.g., BECCS).

Table 5 includes the list of dispatchable generation technologies, agreed with IEAGHG, which were investigated in our technoeconomic analysis. These technologies include unabated fossil fuel thermal plants, power CCS, and other low carbon dispatchable technologies. Considering that power CCS and dispatchable low carbon generation (excluding nuclear) are nascent technologies, the parameters for projects have been adjusted based on three commissioning years considered in this study – 2025, 2030 and 2035. These commissioning years represent first of a kind (FOAK), second of a kind (SOAK) and n^{th} of a kind (NOAK) project, respectively. The CAPEX and OPEX costs are the primary variable for these commissioning years given NOAK plants were expected to be cheaper than FOAK plants due to learning rates and technology improvements. However, pre-development and construction times and efficiencies also benefit from previous project learning. NGCCs and coal plants do not benefit from learning rates as they are already mature technologies.[54]

Table 5: Types of generation used within the modelling.

Unabated fossil	Power CCS	Other dispatchable low carbon
NGCC w/o PCC	NGCC with PCC (90%)	Nuclear[55]
Coal w/o PCC	Coal with PCC (90%)	Battery Energy Storage
	NGCC with PCC (98.5%)	
	Coal with PCC (99%)	
	Blue H_2CC	
	Allam Cycle (90%)	

[53] https://bester.energy/en/development-stages-of-renewable-energy-projects/
[54] Although there have been observable improvements in the efficiency for both of these technologies, the improvement rates relative to that of alternative nascent technologies are very small compared to new technologies and hence are neglected.
[55] Nuclear refers to large-scale nuclear reactors currently present in the UK and not to smaller and more responsive Small Modular Reactors (SMRs).

4.2 Key assumptions

4.2.1 Cost structure

To calculate the LCOE for a given technology, the key considerations include the annualised CAPEX, fixed OPEX, variable OPEX, alongside fuel cost, carbon prices and, finally, transmission and storage.

The CAPEX for various technologies (see Table 2 within Section 2.4.2) is annualised based on an assumed lifetime for projects and discount factor. Instead of using over-night costs, the CAPEX was calculated by considering the percentage of CAPEX allocated to pre-development and construction and the time for each of the processes. This is to reflect the impact that each of the times has on the LCOE. The general trend going from FOAK to NOAK projects was a reduction in pre-development costs and in pre-development and construction times. Furthermore, there is a significant reduction in CAPEX between FOAK and NOAK plants associated with the efficiencies learnt because of successive projects being constructed. These are illustrated in £/kW in Figure 5 below. It should be noted that the CAPEX for H_2CC configuration does not include capital costs for hydrogen generation, which is assumed to be delivered over the fence.

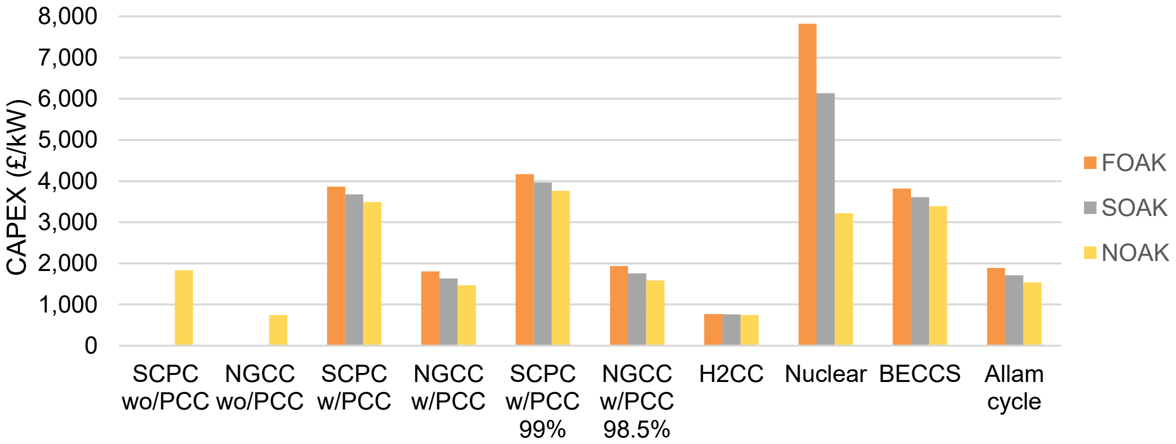


Figure 5: The CAPEX for each generation technology used within the model.

Table 6 shows the pre-development cost percentage and time for FOAK, SOAK and NOAK projects. The pre-development percentage is a percentage of the CAPEX. Table 7 shows the construction cost percentage and time for FOAK, SOAK and NOAK projects.

Table 6: Pre-development costs as a percentage of the CAPEX and associated time for FOAK, SOAK and NOAK projects, respectively.

Technology	FOAK		SOAK		NOAK	
	Pre-development percentage (% of CAPEX)	Time (years)	Pre-development percentage (% of CAPEX)	Time (years)	Pre-development percentage (% of CAPEX)	Time (years)
SCPC wo/PCC	N/A	N/A	N/A	N/A	1.91	3
SCPC w/PCC	1.63	5	1.63	3	1.63	3
SCPC w/PCC 99%	1.63	5	1.63	3	1.63	3
NGCC wo/PCC	N/A	N/A	N/A	N/A	1.91	2
NGCC w/PCC	2.42	5	2.42	4	2.42	2
NGCC w/PCC 98.5%	2.42	5	2.42	4	2.42	3
H2CC[56]	2.42	5	2.42	3	1.91	2
Nuclear	5.53	5[57]	4.43	5	3.33	5
BECCS	2.42	5	2.42	4	2.42	2
Allam cycle	1.16	6	1.16	6	1.51	6

Table 7: Construction costs as a percentage of the CAPEX and associated time for FOAK, SOAK and NOAK projects, respectively.

Technology	FOAK		SOAK		FOAK	
	Construction percentage (%)	Time (years)	Construction percentage (%)	Time (years)	Construction percentage (%)	Time (years)
SCPC wo/PCC	N/A	N/A	N/A	N/A	98.09	4
SCPC w/PCC	98.37	5	98.37	4	98.37	4
SCPC w/PCC 99%	98.37	5	98.37	4	98.37	4
NGCC wo/PCC	N/A	N/A	N/A	N/A	98.09	3

[56] Note: No techno-economic data exists validated by real tests of 100% H2GT and regulative questions remain unanswered (e.g. NOx formation and the cost of deNOx systems). However, examples of H_2 mixing in CCGTs demonstrate promising results that underly the assumptions for equating the NOAK cost of H2CCGTs with CCGTs.
[57] Taken from Projected Costs of Generating Electricity, 2020 Edition, IEA

NGCC w/PCC	97.58	5	97.58	4	97.58	3
NGCC w/PCC 98.5%	97.58	5	97.58	4	97.58	3
H2CC[56]	97.58	5	97.58	4	98.09	3
Nuclear	94.47	8	95.57	8	96.67	8
BECCS	97.58	5	97.58	4	97.58	3
Allam cycle	98.84	6	98.84	6	98.49	6

4.2.2 Fuel price scenarios

Figure 6 shows the three fuel price scenarios which are explored in this model for different fuel types from 2019 to 2090 based on IEA data. For gas (left) we observe a slight decrease and increase for low and central fuel prices, respectively. However, for the high fuel price scenario we observe an increase from 2019 to 2030 in such that the fuel price rises linearly from 11.5 £/MWh to 17.8 £/MWh. A similar trend is observed for coal (middle), but with a rise from 2019 to 2030, but a decrease is observed in the price thereafter which then levels off at 7.0, 6.4 and 5.5 £/MWh, respectively. Finally, for blue H_2, we do not see any changes in fuel prices going from 2020 to 2050.[58] The prices for low, central, and high are fixed and do not deviate. This pattern is also seen in biomass, electricity, and uranium, whereby there is no difference in fuel prices going from low to high scenarios, these fuel prices are given in Table 8. Within all modelling runs, the central fuel price scenario was used. All prices are taken from IEA World Energy Outlook 2019 scenarios for Europe[59] (excluding electricity costs which come from internal EE modelling and is reflective of GB).

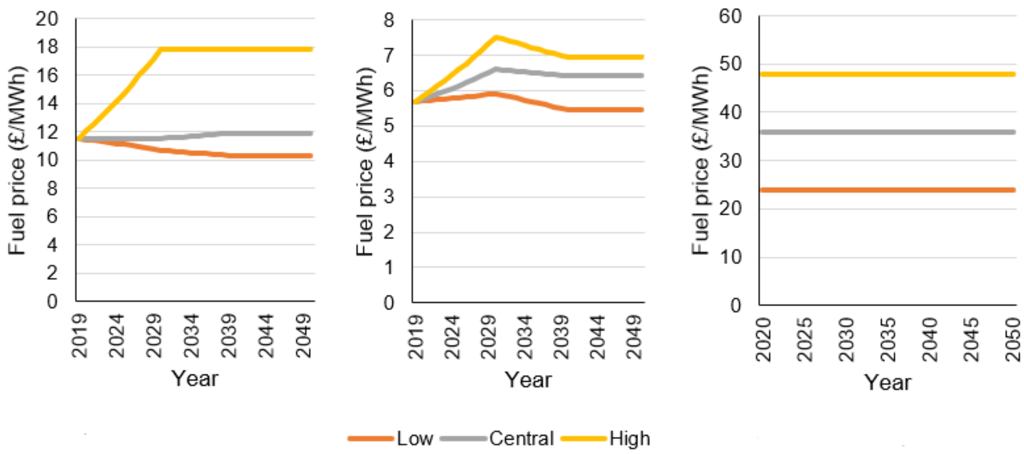
Table 8: Fixed fuel price for biomass, electricity, and uranium for low, central and high fuel prices.

Fuel	Fixed fuel price (£/MWh)
Biomass	27.0
Electricity	54.7
Uranium	1.5

Figure 6: The fuel price scenarios for gas, coal, and Blue H2, respectively.

Gas **Coal** **Blue H_2**

[58] Based on a projected cost for blue H_2 of 1.00-2.00$/kg$H_2$ which is stated in the [Global Hydrogen Review, 2021 Edition, IEA]
[59] These scenarios pre-date both COVID-19 and the Russian invasion of Ukraine.



4.2.3 Carbon price scenarios

The modelling draws on two carbon price scenarios (1) a central and (2) a high scenario[60]. The two scenarios assume a linear increase in the carbon price for each year starting at 48.2 and 52.2 £/tCO_2 in 2019, for central and high, respectively[61]. Figure 7 shows the two carbon price scenarios. We observed a noticeable jump in price for the High scenario around 2035 which then continues to grow linearly each successive year.

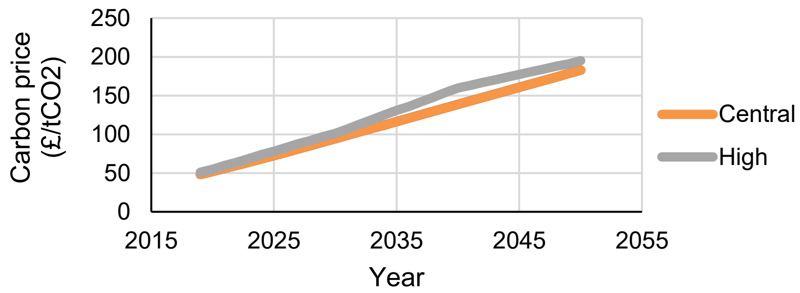


Figure 7: The different carbon price scenarios used within the modelling.

4.2.4 Costing of batteries

This analysis includes the battery energy storage. At low load factors, battery storage could play a similar role to other dispatchable generation. However, it is worth noting that battery storage is distinctly different to the other technologies included in this analysis as it requires periods where there is a surplus in generation to recharge for future dispatch. The cost associated with this is accounted for in the fuel cost component of our modelling. Furthermore, in our whole system dispatch modelling (introduced in section 5), energy storage is dealt with independently to other dispatchable generation to account for this difference from a whole system perspective.

A further variation in our approach to battery storage is through our modelling of the CAPEX associated with battery storage projects. As mentioned previously, the CAPEX decreases from FOAK projects to SOAK and NOAK projects, to account for increasing efficiencies and learnings in project construction. However, as the cost of battery energy storage system (BESS) projects is decreasing at such a rapid rate, annual NREL

[60] Modelled from IEA WEO 2021 carbon prices for advanced economies with net zero pledges within (1) the sustainable development and (2) the net zero by 2050 scenarios, respectively.
[61] International Energy Agency (2022), World Energy Outlook 2022, IEA

projections were used for the cost of BESS in the scenario years. NREL projects rapidly falling BESS costs between now and 2035[62]. Similarly, the IEA[63] and BNEF[64] expect similar cost reductions of batteries up to 2035.

BESS costs are split into power capacity and energy capacity components. The power capacity costs are on a £/kW basis and reflect the price of the inverter and other power component costs that dictate the maximum power output of the BESS. The energy capacity costs are on a £/kWh basis and are primarily dictated by the cost of the battery packs to store energy.

Unlike other dispatchable generation investigated in this analysis, by nature of being energy storage, the configuration of a BESS changes as the load factor increases. At higher load factors, BESS is required to store more energy to ensure it can deliver the energy for the required load factor. As such, for a given power capacity, as the load factor increases, the energy capacity of a BESS must increase. This is reflected by the duration (hours) of a BESS (the MWh of energy capacity divided by the MW of power capacity).

In this analysis, we assumed that battery storage has diurnal operation, cycling once a day. This reflects the standard cycling profile of a BESS. As such, the load factor represents what percentage of the day a BESS must discharge over and hence dictated the necessary duration of a BESS. For example, for a load factor of 10%, a BESS must discharge for 2.4 hours per day. Therefore, the duration for a BESS with a 10% load factor is 2.4 hours. The maximum load factor that a BESS can achieve is 50% (as we assume equal charge and discharge rates in our operation).

It is assumed that BESS with diurnal use participate in wholesale arbitrage. Therefore, they charge at the cheapest hours of their duration on the wholesale power market and discharge at the most expensive hours of their duration on the wholesale power market. Therefore, for each load factor, the average cost of electricity (which is the fuel cost input to the model) has been weighted to reflect the purchase of electricity in the cheapest available wholesale market.

4.3 Modelling results

This section describes the results for the techno-economic modelling. This includes the LCOE for each dispatchable energy generation source and the lowest LCOE is determined for each load factor value for 2025, 2030 and 2035, respectively. Furthermore, a cost breakdown is given to understand which cost components contribute most within the LCOE.

4.3.1 LCOE in 2025 – Unabated gas dominating dispatchable generation

Figure 8 (a) shows the LCOE of various energy generation technologies in 2025 as a function of load factor as well as (b), the best LCOE as a function of load factor with an associated cost breakdown of the LCOE values.

[62] Cost projections taken from NREL.Cost Projections for Utility-Scale Battery Storage: 2021 Update
[63] IEA, Future cost of electricity storage and cost competitiveness
[64] Battery pack prices derail trend in 2022: BNEF (kallanish.com)

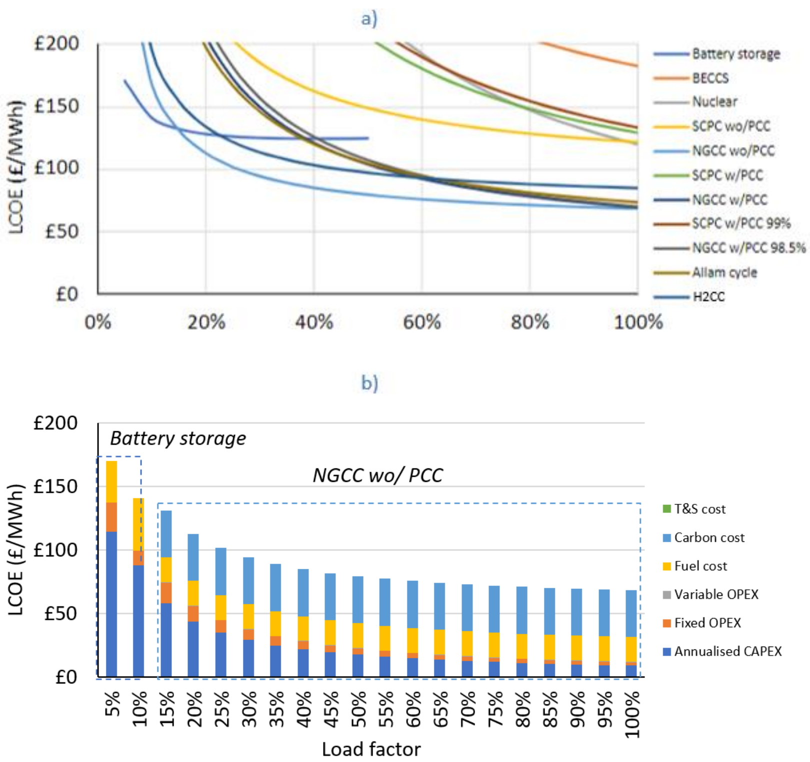


Figure 8: (a) LCOE for various power generation technologies and (b) best LCOE with an associated cost breakdown as a function of load factor for 2025.

Figure 8 (a) presents a reduction in LCOE for increasing load factors for all options. A generation mix of battery storage and unabated gas is predicted for 2025. Battery storage exhibits the lowest LCOE for load factors between 5-10%, while unabated gas exhibits the lowest LCOE for load factors between 15-100%.

The LCOE of batteries ranges from £141-170/MWh, while at its lowest economical load factors (15%), unabated gas starts at £131/MWh and falls to £68/MWh for load factors above 90%. At high load factors, the cost competitiveness of unabated gas becomes challenged by abated gas options. For load factors of 100%, gas with CCS exhibits a predicted LCOE of £70/MWh, and has effectively reached price equivalence. Apart from battery storage at very low load factors, all other FOAK low carbon alternatives exhibit LCOEs which are too high to be incorporated within the energy mix on economic merit alone. This is because the CAPEX associated with FOAK costs is too great to compete with the established market alternatives, even though, by 2025, carbon cost is making up a significant proportion of the LCOE of unabated gas (over 50% for load factors greater than 50%).

4.3.2 LCOE in 2030 – Battery storage & gas turbines with CCS phase out unabated gas

Figure 9 (a) shows the LCOE of various energy generation assets in 2030 as a function of load factor as well as (b), the best LCOE as a function of load factor with an associated cost breakdown of the LCOE values.

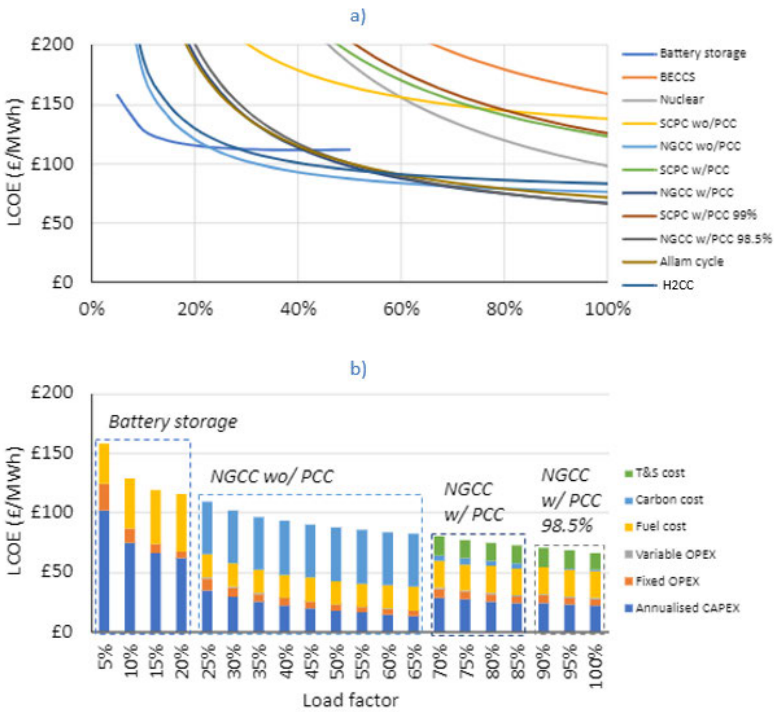


Figure 9: (a) LCOE for various energy generation and (b) best LCOE with an associated cost breakdown as a function of load factor for 2030.

Figure 9 (a) presents a further reduction in LCOE of all low carbon generation types. Decreases in the LCOE can be observed in 2030 resulting from SOAK projects. These reductions are most visible for battery storage and gas with CCS. For low load factors, batteries continue to exhibit the lowest LCOE starting at 155 £/MWh. However, due to decreasing battery costs (11% drop in CAPEX from 2025), battery storage is now the optimal generation type up to 20%, compared to 10% in 2025. Unabated gas continues to dominate the middle load factors (25-65%), despite high carbon costs heavily influencing its LCOE, which ranges from £89-109/MWh where it is cost competitive. For load factors above 70%, gas with CCS becomes the optimal LCOE. The emergence of unabated gas is due to the projected decrease in the CAPEX for SOAK projects combined with an increase in carbon costs which embody 50% of the LCOE for unabated plants. Between 2025 and 2030 there is a 20% increase in carbon cost from 37 £/tCO_2 to 45 £/tCO_2. This increase becomes so influential that at loads factors above 90%, the LCOE of NGCC w/ PCC with 98.5% capture rates is favoured within the generation mix. However, unabated gas still occupies almost half of the generation mix for load factors between 25 - 65% despite the increased carbon cost.

When switching to a high carbon price scenario, LCOE for SOAK abated gas fuelled generation becomes lower than that of unabated gas generation for load factors between 60-100%. Furthermore, for load factors above 75%, it becomes more economical to go adopt abated gas generation with 98.5% capture rates.

4.3.3 LCOE in 2035 – Low carbon generation completely phases out unabated gas

Similarly, Figure 10 shows the LCOE of various energy generation in 2035 as a function of load factor (a) as well as the best LCOE as a function of load factor with an associated cost breakdown of the LCOE values (b).

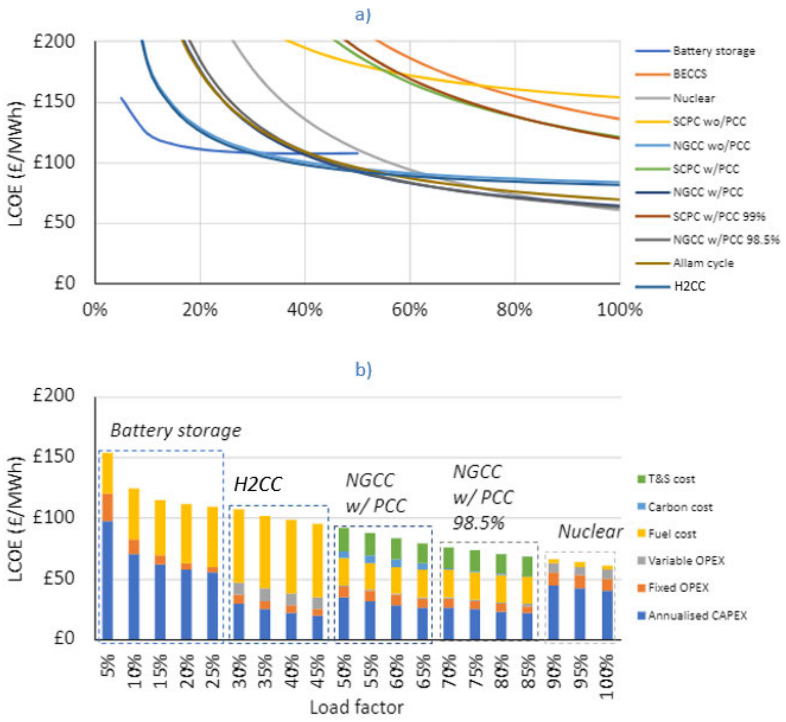


Figure 10: (a) LCOE for various power generation technologies and (b) best LCOE with an associated cost breakdown as a function of load factor for 2035.

Figure 10 (a) presents a further reduction in LCOE of all low carbon generation types as a result of 2035 being associated with NOAK projects and the decreases to CAPEX relative to FOAK and SOAK projects they introduce. The LCOE for batteries continues to decrease, increasing the range of load factors that battery storage is optimal at to 25%.

The effects of NOAK projects have on decreasing plant CAPEX results in the LCOE of H2CC becoming marginally smaller than that of unabated gas with an average LCOE gap of 2%. Blue H_2 exhibits the lowest LCOE between load factors of 30-45%. This emergence of blue hydrogen for central load factors is explained through the increased carbon cost. This leads to blue hydrogen offering a cheaper fuel source than natural gas with associated carbon costs in 2035. It is assumed that by 2035 the CAPEX of NOAK H2CC plants has reached price parity with that of unabated gas NGCC plants. Therefore, the performance of H2CC compared with unabated gas turbines is largely dictated by fuel and carbon prices.

Abated gas generation is shown to replace unabated gas, occupying the generation mix for load factors between 50-85%. However, additional investment for NGCC with higher capture rates proves to be economical for load factors above 70% by helping to further mitigate carbon costs.

Nuclear appears in the generation mix offering the lowest LCOE for load factors above 90%. However, this is heavily dependent on large reductions in the CAPEX of nuclear power between FOAK and NOAK projects. Literature suggests that the CAPEX of nuclear power could fall by 60% between FOAK (based on available data on Hinkley Point C) and NOAK (IEA data[65]) projects. A reduction of this scale is unlikely.[66] However, should it occur, nuclear will be optimal to provide the lowest cost base generation. If these cost reductions were not to occur, as seen in 2030, high capture NGCC would continue to offer the lowest LCOE for the highest load factor values.

[65] Taken from Projected Costs of Generating Electricity, 2020 Edition, IEA.
[66] CAPEX decreases taken from the Net Zero by 2050 - A Roadmap for the Global Energy Sector published in 2021, predicts a 30% decrease in CAPEX from 2020 to 2030.

Crucially, this analysis suggests that by 2035, the cost-optimal energy mix for dispatchable power will be fully decarbonised, composed of battery storage, H2CC, and power CCS. This is largely thanks to increasing carbon costs (in the central carbon price scenario) and reductions in CAPEX for successive projects.

4.4 Modelling sensitivities

4.4.1 High carbon price

In this sensitivity, the effect of increased carbon prices has been analysed for 2035. A high carbon price scenario is implemented within the model to observe any changes in the generation mix. Figure 11 shows the generation mix in 2035. The capture rate of 98.5% for NGCC becomes more economical than that of NGCC with capture rates of 90% and becomes the lowest cost technology for load factors between 60 – 85%. This means that abated gas with capture rates of 90% is the lowest cost technology for a load factor of 55% only.

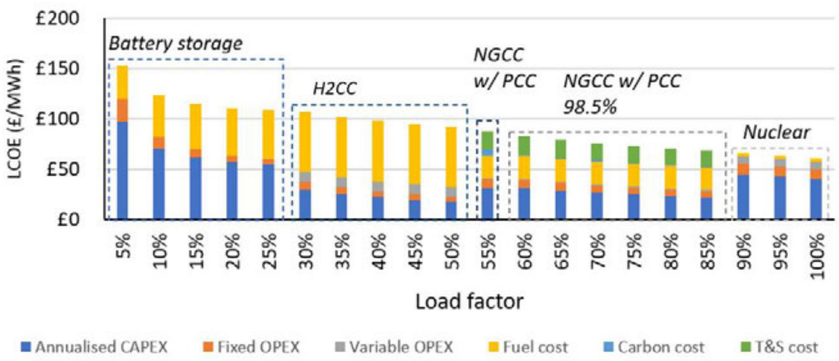


Figure 11: The LCOE of the generation mix in 2035 within a high carbon price scenario.

4.4.2 Reward for negative BECCS emissions

We assume that BECCS plants are remunerated for 50% of the captured emissions at the carbon price[67] in the main findings of this report. This assumption is used to reflect uncertainty around a revenue mechanism for negative emissions, carbon footprint associated with biomass supply chain as well as issues around securing supply of genuinely sustainable biomass. The effects of higher revenues of BECCS plants from captured emissions are explored in a sensitivity in which the share of captured emissions (which are remunerated) is increased from 50% to 100%. We call this share the negative emissions factor. We further analyse the difference when moving from a central to high carbon price scenario.

[67] It is worth noting that negative emissions are expected to have a higher value than the carbon price applied to emissions, however, given the uncertainty around this price, we have applied this price to BECCS for completeness.

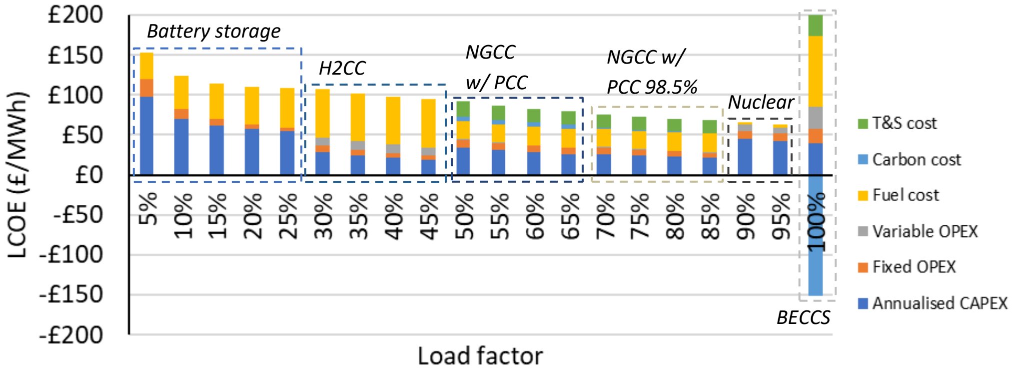


Figure 12: The LCOE of the generation mix in 2035 with a 100% negative emissions carbon price (central) factor.

Figure 12 shows the LCOE of the generation mix in 2035 with a 100% negative emissions factor for BECCS plants and the central carbon price. Figure 13 shows the LCOE of the generation mix in 2035 with a 100% negative emissions factor with the high carbon price. For load factors between 75 – 100% BECCS is the most economical option with LCOE values between 74-42 £/MWh. Like the central carbon price scenario, the LCOE of BECCS is dominated by the negative carbon cost resulting from the negative emissions which assumes remuneration of all captured emissions at the level of the carbon price.

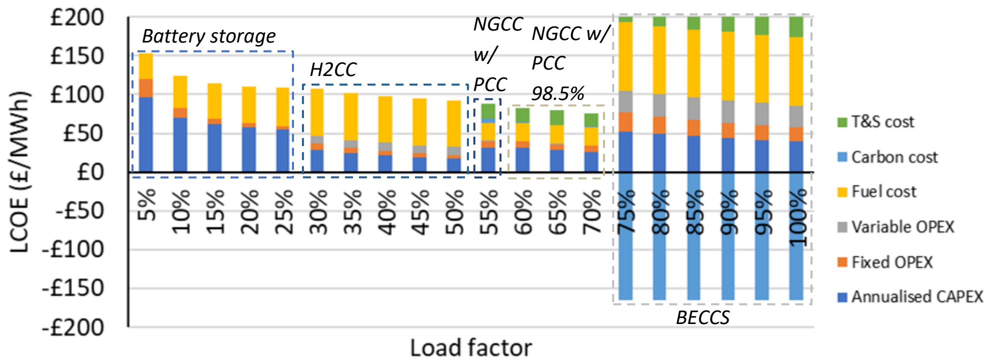


Figure 13: The LCOE of the generation mix in 2035 with a 100% negative emissions carbon price (high) factor.

4.4.3 Increased transport and storage costs

The effects of increased T&S costs are analysed for 2030. A higher T&S cost scenario of 60 £/tCO_2[68] is implemented within the model to observe any changes in the generation mix. Figure 14 shows the generation mix in 2030. Relative to a central T&S cost scenario, abated gas with 90% capture rates becomes the lowest cost technology option for load factors between 90 – 100% while simultaneously removing the presence of abated gas with 98.5% capture rates. The overall effect seen is a larger share of unabated gas within the generation mix, exhibiting the lowest LCOE for load factors between 25 – 85%.

[68]20, 40 and 60 £/tCO2 is used the low, central, and high T&S scenarios, respectively. Source: Porthos CCS - Transport and Storage (T&S) Tariff Review

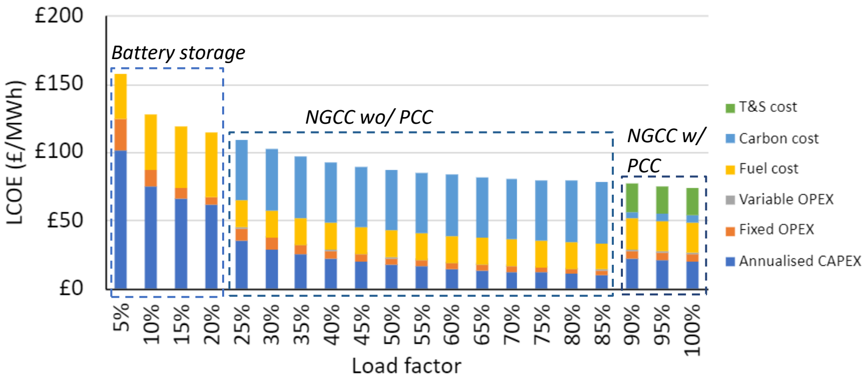


Figure 14: The LCOE of the generation mix in 2030 within a high T&S scenario.

5. Power CCS competing with and complementing renewable generation

In this chapter we explore the role of power CCS n future decarbonised power systems. Several countries including the UK have declared the goal to largely decarbonise their power systems by 2035. A decarbonised power system is a key enabler of decarbonisation in other sectors through electrification. Such a future power system should satisfy the three key objectives of energy policy summarised in the energy trilemma: reliability, sustainability, and affordability. Reliability refers to the capacity of the energy system to securely meet current and future energy demand at all times, sustainability refers to minimising carbon emissions and other environmental harm, and affordability refers to the ability to provide low cost energy to final consumers.

To ensure a decarbonised power system by 2035, significant investment into low carbon generation needs to be made in the next 5-10 years. However different versions of a decarbonised power system are possible, some based largely on dispatchable power generation technologies such as power CCS and nuclear, others based largely on variable renewable energy (VRE), mostly wind and solar. For investors of power CCS plants it is important to understand the role of power CCS in each of these alternative versions of a future power system. How much capacity of power CCS plants could be required? Power CCS plants might be needed in both a system based on mainly dispatchable generation technology and one mainly based on VRE. However, their utilisation would highly differ. Will power CCS plants be run as baseload plants, mid-merit plants, or as peaking plants? Which technologies will compete with power CCS to provide low carbon dispatchable power?

To gain a better understanding of the drivers determining the answers to these questions, we model various versions of a decarbonised power system in the UK in 2035 with different generation mixes and analyse the role that power CCS will play in them. A key focus of our analysis is the size of the required dispatchable fleet in each of the alternative future power systems and its load factor distribution, i.e., what amounts of capacity are run at which load factor. The LCOE analysis of the previous chapter determined for each load factor the dispatchable technology with the lowest cost. Combining these two results thus allows us to determine the maximum amount of capacity per technology which could be competitive in the investigated future versions of a future power system.

We compare the different generation mixes in terms of their total annual cost as that will be a key factor determining the future mix. Other factors are likely to be efforts by governments to reduce reliance on energy imports as well as environmental concerns such as those around potential upstream emissions of natural gas. However, these are not the focus of our analysis.

5.1 Sources of flexibility in future power systems

Within an electricity grid, the supply and demand of energy must be continuously balanced to ensure safe and reliable operation. Flexibility is the ability to shift energy consumption or generation in either time or location in order to match supply and demand and ensure this balance. Traditionally, flexibility was mainly provided by the supply side which was dominated by dispatchable generation, typically by coal and gas fired power plants. However, with the target of a fully decarbonised grid these sources of flexible generation will need to be replaced with low carbon options. VRE plants are low carbon but they are inherently inflexible: they cannot adjust their generation according to demand but produce power according to resource availability (wind, solar). In systems with high penetration of VRE there will thus be a heightened demand for flexibility of other assets in the system. This flexibility could be provided from other parts of the supply side, e.g., from low carbon dispatchable generation such as Power CCS. However, it could also be provided from sources on the demand side such as electric vehicles which shift their consumption to times of high VRE output. In the following section we briefly introduce the main sources of flexibility in power systems.

5.1.1 Demand side response

Demand side response (DSR) refers to shifting electricity consumption in time according to system needs, e.g., move consumption out of times of the peak demand on the electricity grid and to times of high output of wind and solar plants. This helps to reduce the peaks and troughs of electricity demand, decreasing the need to build spare capacity into the network and generation infrastructure and increasing the possible integration of renewable energy. As mentioned, traditionally the supply side followed the demand side in the electricity system and demand side response was only provided to a limited extent, by some industrial sites offering to reduce demand for a limited amount of time in periods of high system stress. Roll out of VRES will however increase the need for DSR in the system and electrification of some energy uses creates demand segments with high flexibility. This holds true for electric vehicles, which will be plugged into chargers for a much longer period of time (for example overnight) than required to meet their charging demand (typically no more than one hour). The importance of DSR in the electricity system is thus expected to increase significantly. DSR measures were not included in the modelling approach.

5.1.2 Storage

Storage assets absorb energy at times of low demand, store it and discharge it at times of high demand. It acts as an intermediary between demand and supply. Apart from balancing supply and demand, storage can also be used to manage flows on electricity networks. In systems of high VRE penetration there will be an increased demand for storage, absorbing renewable energy which would otherwise be curtailed and displacing expensive generation from peaking plants at times of high demand. Batteries and H2P2P are discussed further in Section 5.2.2.

Storage can be categorised by its discharge duration, from seconds to multiday periods. Batteries are a highly efficient technology to provide short duration response from seconds to a few hours. They can furthermore respond to system needs more rapidly (in a matter of seconds) than most other technologies (including thermal generation). Therefore, they have started to dominate markets for rapid response services procured by electricity network operators.

Another technology which could provide long duration storage services is H2-power-to-power (H2P2P) storage. H2P2P consists of electrolysers which convert renewable electricity which would otherwise be curtailed to hydrogen, store that hydrogen in tanks at small scale or underground geological formations such as salt caverns at large scale, and use H2CCs to combust the stored H2 to generate electricity at times of higher demand. a.

5.1.3 Interconnection

Electricity interconnectors are high-voltage cables that connect the electricity systems of neighbouring countries. Interconnectors can provide resilience to the grid through the supply of electricity from generation overseas during times of low domestic renewable output generation / high domestic demand or exports during times of high renewable output. The presence of interconnectors can help reduce the required domestic generation capacity and also increase its utilisation. A key driver for synergies unlocked by interconnectors are complementary patterns of demand (e.g., peak demand during midday in one country vs peak demand in the evening in another) as well as renewable generation (different patterns of wind).

Interconnectors linking the UK to other energy systems could play an important role both for the import and export of energy. Without the presence of interconnection, the UK energy system would require greater sources of dispatchable generation as well as alternative uses for low carbon electricity during times when supply exceeds demand. The UK already relies heavily on interconnection for balancing electricity demand and supply mismatches resulting from insufficient energy storage and generation capacity. We didn't include interconnection in our modelling approach as this would require modelling supply and generation in neighbouring countries with interconnections to the UK which was outside the scope of the modelling.

5.1.4 Flexible thermal generation

Flexible thermal generation, from gas fired power plants, is currently the dominant source of system flexibility in all power systems, accommodating the variability of demand and VRE output. Dispatchable power generation provides flexibility by reducing power output or shutting down completely when VRE output is plentiful or when demand is low. Similarly, it ramps up or starts up rapidly to cover periods of low VRE availability or rapid increases in demand. It also provides a range of short duration grid services to network operators. Retrofits and retirement/replacement of power plants may be required to improve fleet flexibility, e.g., by increasing ramp rates and reducing minimum stable generation and start up times. Power CCS plants will need to be designed from the start to have a high degree of flexibility in order for them to complement VRE in future power systems. The UK currently has a fleet of about 50 GW of high carbon dispatchable capacity consisting of Peaking (OCGT), Gas CHP, NGCC and Coal plants. The majority of these are fuelled by natural gas (30 GW NGCCs, 6 GW OCGTs).

5.2 Modelling approach

The starting point of the electricity system modelling is the annual demand profile in 2035 in the UK at hourly resolution. This is taken from the NGESO 2020 Future Energy Scenarios (FES) report, scenario 'Leading The Way'. We then model five different generation mixes supplying this demand, as listed in Table 9.

None of these scenarios are meant to be a forecast of the generation mix in the UK. Rather they are chosen to show five different versions of a low carbon supply side in 2035 and illustrate impacts and trade-offs of technology choices.

We want to investigate the role of each dispatchable technology, in particular power CCS, in these future power system versions, i.e., the total installed capacity per technology and its operation. In order to do this, we determine the required generation capacity per dispatchable technology and the hourly operation and subsequent load factors of the dispatchable fleet for each scenario[69]. Furthermore, we calculate the total generation cost broken down into CAPEX, OPEX, fuel and carbon cost, as well as renewable curtailment, in order to compare scenarios in terms of total cost and VRE integration. As a simplification, a fresh start to the fleet is assumed instead of modelling the retrofit of existing units. In all scenarios the power system has to have close to zero emissions, reflecting the UK government's policy target for 2035. Thus, no unabated coal or gas fired plants are deployed.

Table 9: Included generation technologies by scenario.

Scenario number	Scenario name	Generation technologies	Minimised variable
1	Lowest CAPEX	Blue H2CC	CAPEX
2	Lowest fuel cost	Nuclear	Fuel cost

[69] However, considerations for the spatial constraints on the electricity network was outside of scope for this study and is presented as a recommendation for future work.

3	Optimised	Blue H2CC, NGCC w/PCC, NGCC w/PCC 98.5%, Nuclear	LCOE
4	VRES	Wind, Solar, Blue H2CC, NGCC w/PCC, NGCC w/PCC 98.5%, Nuclear	LCOE
5	VRES & storage	Wind, Solar, Blue H2CC, NGCC w/PCC, NGCC w/PCC 98.5%, Nuclear, Green H2CC, Battery storage	LCOE

5.2.1 Scenario design

In scenarios 1 and 2, only one dispatchable generation technology is used. In scenario 1, only the technology which is cheapest to build among the investigated technologies is deployed. This means the dispatchable fleet is designed in such a way as to minimise CAPEX. In contrast only the technology which is cheapest to run (Nuclear) is deployed in scenario 2. This means the dispatchable fleet is designed to minimise fuel cost. In scenarios 3-5 the dispatchable plants are deployed and dispatched in such a way as to minimise overall generation cost, i.e., the full average levelized cost of electricity (LCOE) of the generation mix, including CAPEX, fuel cost, fixed OPEX, variable OPEX, and carbon cost. To achieve this, each technology is deployed and run at the load factor at which it has the lowest LCOE, see lowest cost technology by load factor as illustrated in section 4.3.3 (more on the optimisation of the dispatchable fleet in the following subsection).

In scenarios 4 and 5 we include VRE in the generation mix. The VRE penetration is an exogenous input from the NGESO FES report (Figure 15 below). The penetration is given in terms of annual generation, equivalent to electricity (in TWh) generated by wind and solar. The installed wind and solar capacities are derived using annual load factors of wind and solar in the UK based on historical weather data. The required amount of installed dispatchable generation is then determined from the hourly imbalance between supply of VRES and demand. In scenario 5, we add battery storage and H2P2P storage to the system as long as this provides a net benefit, i.e., the benefit provided by added storage outweighs its cost (more detail on this is given in the next subsection). The addition of storage changes the requirement for dispatchable thermal generation capacity and its operation. This change results from the ability for battery storage to provide dispatchable generation when it is required thus reducing, and at times, eliminating the need for dispatchable thermal generation.

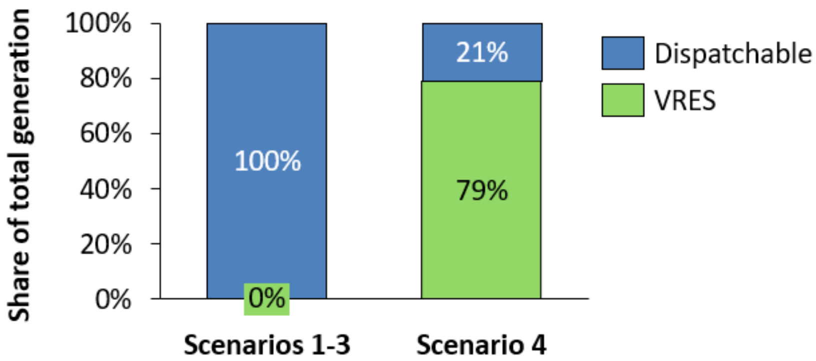


Figure 15: Share of VRE vs dispatchable plants in electricity generation in scenarios 1-4.

5.2.2 Optimisation of the dispatchable fleet

In scenarios 3, 4 and 5 an optimal fleet of dispatchable power plants is deployed to provide the low carbon dispatchable generation required at the lowest cost possible. This is achieved using the following approach:

- The total fleet of dispatchable plants is given by the peak demand (80 GW in scenario 3, see Figure 16)
- This fleet is divided into increments of 1 GW (representing roughly the size of individual thermal power plants)
- We assume the fleet of plants is always dispatched in the same order (i.e., in each hour, plant 1 is always dispatched first, then plant 2, and so on)
- For a given annual demand profile, this leads to number of annual dispatch hours for each plant (see Figure 16)
- This can easily be translated into an annual load factor for each plant of the dispatchable fleet (see Figure 17)
- We then choose for each GW the technology which leads to the lowest LCOE at the corresponding load factor (as determined in chapter 4)

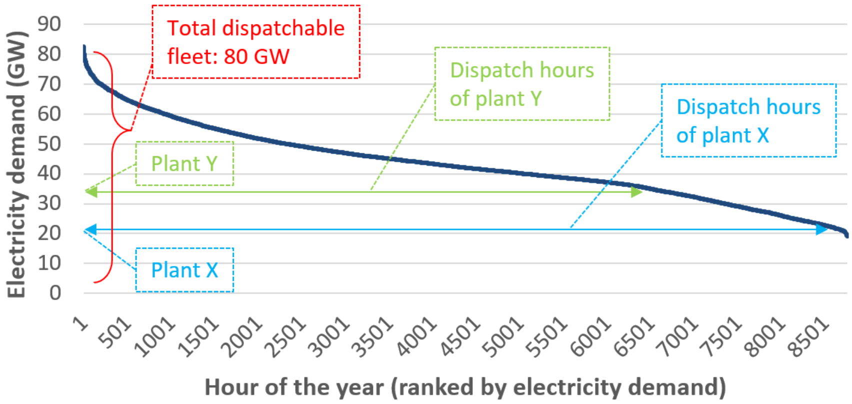


Figure 16: Illustration of the approach used to model the dispatch order of the fleet and corresponding dispatch hours of plants for a given load profile.

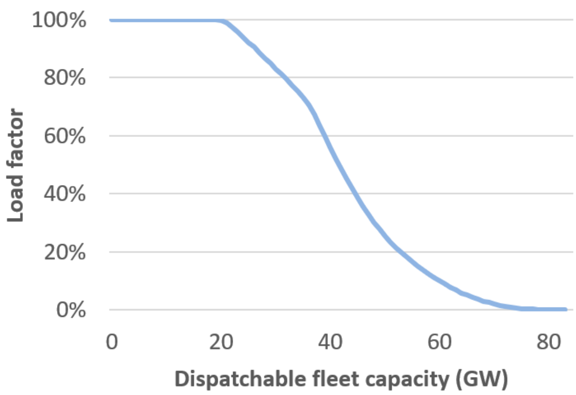


Figure 17: Load factor per 1GW increment of the dispatchable fleet in scenario 3 based on the used fleet dispatch modelling approach.

5.2.3 Modelling of storage in scenario 5

As mentioned above, storage is expected to play an important role in future power systems with high VRES penetration to reduce VRES curtailment as well as expensive thermal generation. Key storage technologies which could play complementary roles in the energy system are battery storage and H2P2P. Table 10 gives a brief description of both options.

Table 10: Description of battery storage and H2P2P storage systems

Battery Storage	H2P2P
Batteries convert electrical energy to chemical energy. The chemical energy is stored and can be converted back to electric energy when required[70]. Typical round trip efficiencies of batteries are 70-90%[71].	Hydrogen Power-to-Power uses an electrolyser to convert electricity to hydrogen, which is stored in gaseous form for later use. The hydrogen is combusted in a gas turbine at times of demand to generate electricity. Typical roundtrip efficiencies of such systems are 30-40%[72].

On a high level, batteries are expensive to build but cheap to use, whereas H2P2P is cheap to build but expensive to use. Batteries have high CAPEX if built for long duration response. This CAPEX increases significantly with each hour of additional response duration. However, they have a high roundtrip efficiency (80-90%) so any MWh discharged requires 1.1-1.25 MWh charged. On the other hand, H2P2P used for long duration response is cheaper to build. The cost of H2P2P storage increase only marginally with each additional hour of response. H2P2P has, however, a low roundtrip efficiency (around 35%), so any MWh discharged requires around 2.9 MWh charged.

Battery storage is thus more economic in applications which only require a short discharge duration (a couple of hours at most) and where the storage is cycled (charged and discharged) many times a year. H2P2P on the other hand is more economic in applications which require a longer discharge duration (several hours up to multi-day periods) and only a few cycles per year.

Key benefits that storage can provide to the electricity system is the reduction of required dispatchable generation capacity as well as fuel cost savings due to use of otherwise curtailed renewable generation instead of combustion of fuel in thermal generation plants. Our electricity system model adds storage in increments to the system. For each increment the model assesses whether battery storage or H2P2P provides a higher net benefit (benefit minus cost) to the system and chooses the storage technology to add accordingly. The model stops adding storage to the system once this does not provide a net benefit anymore. This infrastructure choice and size optimisation process is illustrated in Figure 18, showing net benefits of increments of storage added to an electricity system with high VRES penetration.

The total required dispatchable generation in such a system with high VRES penetration is given by the peak net demand with net demand being the demand minus VRES generation. Our model sequentially adds storage to the system to reduce the peak net demand in regular increments. Each increment of peak net demand reduction requires the same storage capacity in GW terms but with a different storage duration depending on the duration for which the peak net demand is sustained. With increasing peak net demand reduction, the resulting new peak net demand is typically sustained for increasing time periods as storage is used to flatten the peaks and troughs of the net demand profile. Therefore, the required storage duration increases with the level of peak net demand reduction. Subsequently the net benefit provided by batteries decreases with higher levels of peak demand reduction due to the high sensitivity of their CAPEX to duration. On the other hand, the net benefit of H2P2P increases with increasing peak net demand reduction as its CAPEX increase only to a minor extent with longer duration, whereas each incrementally added GW capacity of H2CC gets utilised for more hours and thus provides increasing fuel savings than the previous. This shows how both technologies work in tandem and complement each other.

[70] Australian Academy of Science, How a battery works
[71] https://www.osti.gov/servlets/purl/1409737;
[72] Assuming 60-70% efficiency of the electrolyser and 50-60% efficiency of a CCGT

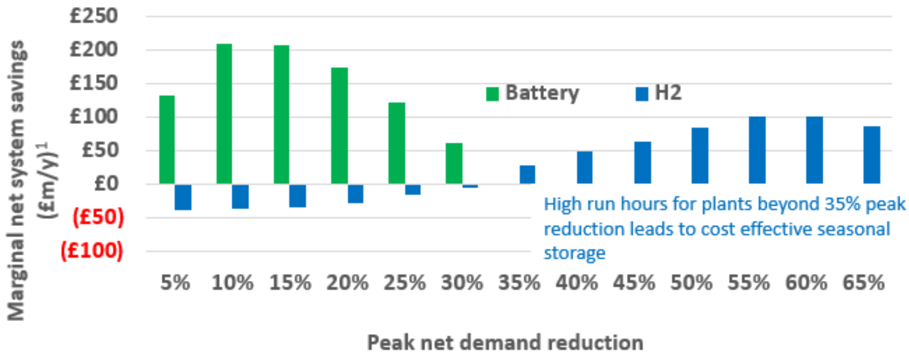


Figure 18: Illustration of marginal savings of batteries and H2P2P against peak net demand reduction.

5.3 Inputs and key assumptions

In this section we list the key assumptions and inputs used in the model with regards to electricity demand, technology cost, and variable renewable energy generation resource in the UK.

5.3.1 Electricity demand

Figure 19 shows the hourly electricity demand profile in the UK in 2035 used in the model. This is the demand profile that needs to be met by the supply side in the five different scenarios. It is the demand profile in the scenario Leading the Way, in the NGESO 2020 Future Energy Scenarios report. The figure also shows the demand profile in 2019[73]. The demand is not shown in chronological order but rather hours are arranged on the x-axis from highest to lowest electricity demand.

By comparing the curves from 2019 and 2035 we can observe an increase in the annual demand including a change in shape which is attributed to the electrification of heat and transport. Peak demand is expected to increase by around 50% from 54 GW in 2019 to 82 GW in 2035 while total annual demand is expected to increase by around 30% from 268 TWh in 2019 to 378 TWh in 2035. The higher increase of peak demand compared to annual demand means that the consumption profile becomes more uneven across the year. This implies a need for significant electricity infrastructure (power lines and generation plants) to meet the peak demand which will be utilised for only a short period of time during the year.

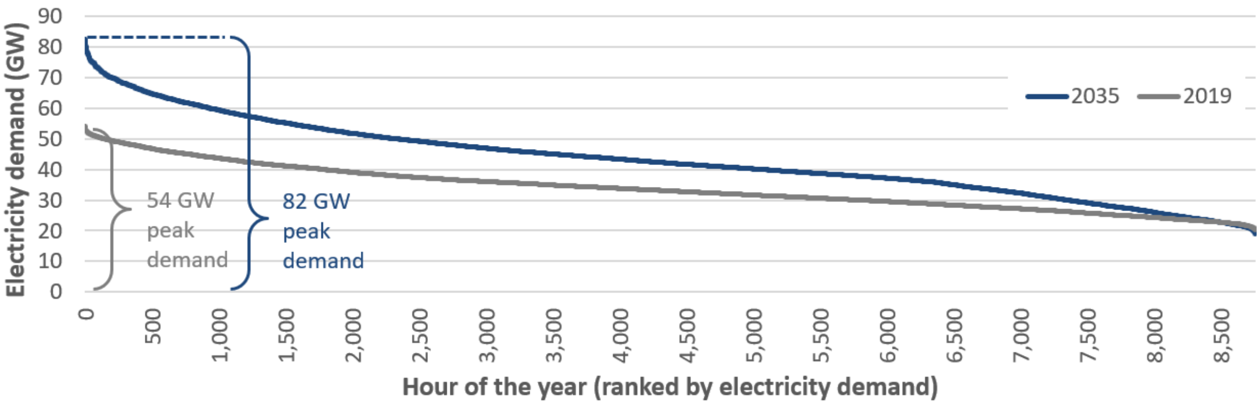


Figure 19: Electricity demand comparison between 2019 and 2035.

[73] Based on the demand profile on the transmission grid as published by NGESO and scaled up to represent the full electricity demand on transmission grid as well as distribution grid as reported by BEIS, Energy Trends (296 TWh).

5.3.2 Dispatchable technology cost

We use the cost assumptions for dispatchable generation technologies deployed in 2035, including NOAK power CCS plants, as described in chapter 4. This leads to the cost optimal technologies per load factor range and corresponding levelized cost of electricity as shown in section 4.4.3. Table 11 below lists load factor ranges and corresponding cost optimal technologies explicitly. Unabated gas is entirely phased out of the generation mix in 2035.

Table 11: Lowest LCOE technology by load factor range.

Load factor range	Lowest LCOE technology
0 - 29	Battery storage
30 - 49	Blue H2CC
50 - 69	NGCC w/ PCC
70 - 89	NGCC w/ PCC (98.5%)
90 - 100	Nuclear

5.3.3 Variable renewable energy cost and performance

Table 12 shows the assumed capacities, load factors, and costs for wind and solar generation.[74] Wind load factor and cost is the average of the data for offshore and onshore wind in the 2020 NGESO Future Energy Scenarios report, weighted by the share of each in the overall installed wind capacity (offshore and onshore). Solar costs are taken from the 2020 BEIS report Electricity Generation Cost. The solar load factor is based on historical solar irradiation data in the UK. Costs have been converted to 2021 £.

Table 12: Cost and load factor assumptions for wind and solar in 2035.

Technology	Installed capacity (GW)	Load factor (%)	CAPEX (£/kW)	Fixed OPEX (£/kW/y)
Wind	84	41	1,000	68
Solar	44	10	454	8

5.3.4 Storage cost assumptions

The cost assumptions for the two modelled storage technologies are listed in Table 13 below. Battery costs are based on the NREL Annual Technology Baseline cost projections (2021 edition). Electrolyser costs are based on the 2020 IRENA report Green Hydrogen Cost Reduction. The CAPEX figures of the report have been multiplied with a Lang factor of 2; which is an estimated ratio of the total cost of creating a process within a plant, to the cost of all major technical components[75]. The assumed value of 2 is high to account for civil works necessary at greenfield sites to establish required electrical and civil works infrastructure. Hydrogen storage cost data is based on the cost estimates for H2 storage in salt caverns in the H21 North of England report. We assume the same cost for green H2 as for blue H2CCs. In both cases we assume that in 2035, cost and performance will be the same as for a NGCC and use the NGCC cost estimate of the 2020 BEIS report Electricity Generation Cost.

Table 13: Storage cost assumptions in the modelling.

Technology	Capex (£/kW)	Capex (£/kWh)	Fixed OPEX (£/kW/y)	Fixed OPEX (£/kWh/y)	Lifetime (years)

[74] VRES generation is based on historical generation profiles on GB system. Extend periods of low demand are addressed economically through the optimal deployment of green H_2 storage or dispatchable generation.
[75] Chemical Engineering Projects, The Factorial Method of Cost Estimation

Battery BOS[76]	155	N/A	3.88	N/A	20
Battery pack	N/A	107.97	N/A	2.70	20
H2 electrolyser	1,000	N/A	10.00	N/A	15
H2 storage	N/A	0.29	N/A	0.01	40
Green H2CC	746	N/A	21.30	N/A	25

5.4 Modelling results

In this section we discuss the modelling results. We first compare high level outputs across the five scenarios, total annual generation costs, installed capacities, and load factors. Then we explore the modelling results in more detail, focusing on scenarios 3, 4 and 5. These have significantly lower costs than scenarios 1 and 2 and thus present much more cost optimal generation mixes.

5.4.1 Overview and cost comparison

Figure 20 shows annual generation costs in the five modelled scenarios broken down by cost category. Key outputs which can be observed are:

- Using an optimised mix of low carbon dispatchable fleet (scenarios 3, 4 and 5) rather than only one dispatchable technology (scenarios 1 & 2) leads to significantly lower generation costs. While scenario 1 shows the lowest CAPEX and scenario 2 the lowest fuel cost, their total cost is much higher than in scenarios 3-5, which deploy a mix of technologies rather than only one.
- Deployment of low-cost variable renewable energy (VRES) offers an annual saving ~£1.8bn compared to a generation mix without renewables, corresponding to a 6% saving (scenario 4 vs 3).
- Deployment of battery and H2P2P storage provides an annual net saving of ~£800m, corresponding to a 3% reduction of generation cost (scenario 5 vs 4). This corresponds to a 9% generation cost saving (~£2.6bn), of scenario 5 (VRES & storage) compared to scenario 3 (Optimised).

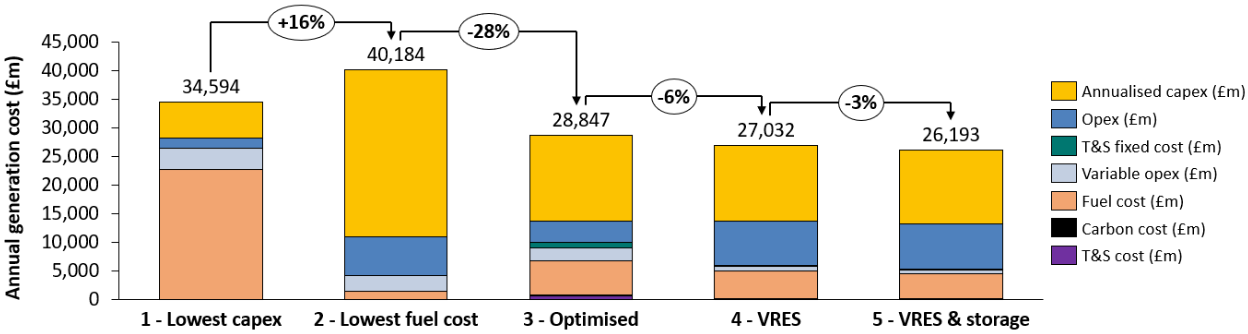


Figure 20: Showing the annual generation cost for the modelled scenarios.

Figure 21 and Table 14 show the installed capacities of dispatchable generation technologies in the five scenarios. In Scenario 3 without VRES, a broad mix of dispatchable technologies is deployed, including 27 GW of nuclear, 15 GW of NGCCs with post combustion capture as well as 40 GW of blue H2CCs. In the scenarios with VRE, blue H2CCs are the dominant dispatchable generation technology with 68 GW of capacity.

Figure 22 shows the average load factor of the total installed capacity of any of the investigated technologies. Due to the used approach, these are aligned with the load factor ranges assigned to each technology as detailed in Table 11 with the exception of blue H2CCs. These are deployed at load factors below 30% even though Table 11 suggests batteries as the optimal technology for this load factor range in scenario 4 and 5.

[76] Battery optimization system (BOS)

This is because in scenario 4 no battery or H2P2P storage is deployed and in scenario 5, the storage (battery and H2P2P) deployment is based on a different optimisation process which takes into account system specific benefits (reduction of VRES curtailment and dispatchable capacity requirement), rather than on the identification of lowest LCOE technology per load factor only. The load factor of the H2CC fleet is below 15% in all scenarios (blue and green H2CCs combined in scenario "VRES & storage"). Table 15 lists the annual generation per technology. It needs to be noted that the wind and solar generation includes curtailed generation. Therefore, the total generation in scenario 4 and 5 is higher than in scenarios 1-3. Furthermore, the generation from batteries and green H2CC in scenario 5 is exclusively based on utilisation of VRES curtailment and thus corresponds to the reduction of curtailment between scenario 4 and 5.

Table 14: Installed capacity per generation technology in the five modelled scenarios

	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5
Installed capacity (GW)					
Nuclear	0	83	27	0	0
NGCC w/PCC 98.5%	0	0	11	0	0
NGCC w/PCC	0	0	4	4	3
Blue H2CC	83	0	40	68	32
Green H2CC	0	0	0	0	30
Battery storage	0	0	0	0	9
Wind	0	0	0	84	84
Solar	0	0	0	44	44

Table 15: Annual generation per generation technology in the five modelled scenarios

	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5
Annual generation (TWh)					
Nuclear	0	378	234	0	0
NGCC w/PCC 98.5%	0	0	76	0	0
NGCC w/PCC	0	0	20	19	14
Blue H2CC	378	0	48	72	67
Green H2CC	0	0	0	0	4
Battery storage	0	0	0	0	6
Wind	0	0	0	303	303
Solar	0	0	0	39	39
Total	**378**	**378**	**378**	**433**	**433**
of which VRE curtailment	0	0	0	55	37

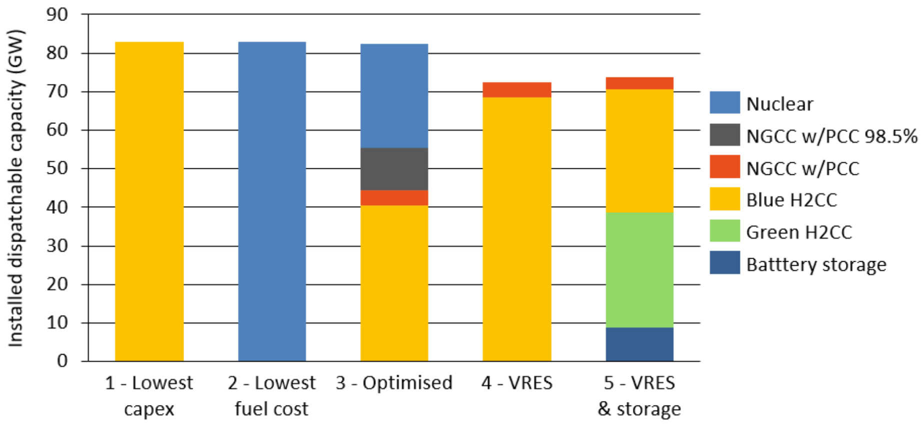


Figure 21: Installed capacities per dispatchable generation technology in the five scenarios.

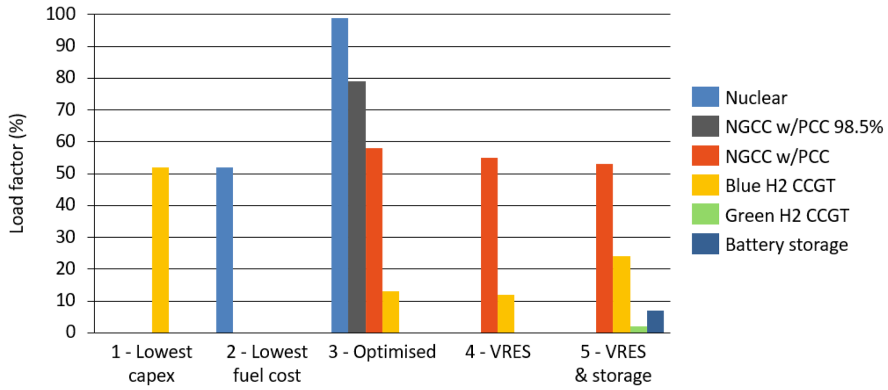


Figure 22: Average load factor of the installed capacity per technology in the five scenarios.

5.4.2 Scenario 3 – optimised dispatchable fleet without renewables

In scenario 3 all electricity demand is met by dispatchable generation. Figure 23 shows installed capacity and generation per dispatchable technology. We observe that significant capacity of all considered dispatchable generation technologies is deployed of which Blue H_2CCs provide the largest share of capacity (~50%, 40 GW), but only about 10% of generation. Nuclear provides about 30% of capacity (27GW), but only 60% of total generation while NGCC w/ PCC with 98.5% capture provides about 10% of capacity and 20% of generation. This results in power CCS providing a combined 144 TWh of generation which is about 40% of demand.

Figure 24 shows the load factor for each increment of the dispatchable fleet in scenario 3 along with the load factor ranges of dispatchable technologies and subsequently installed capacities per technology.

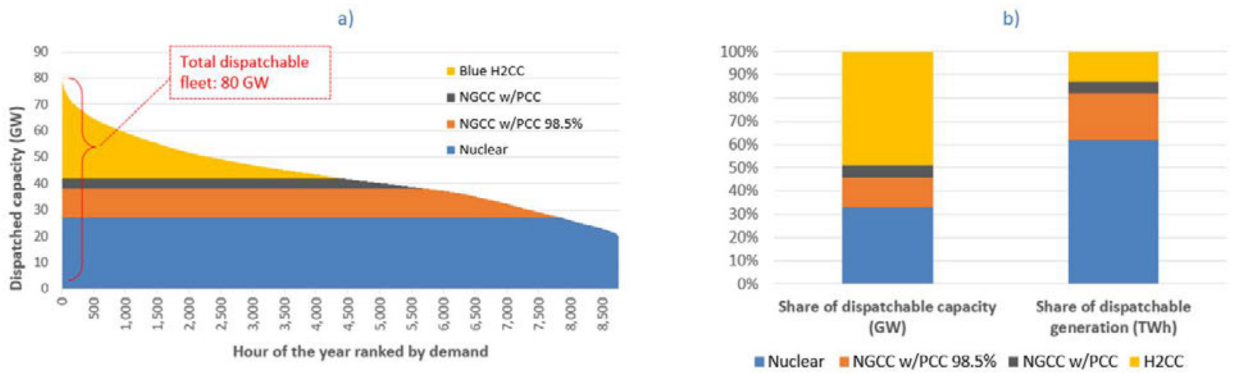


Figure 23: (a) Load duration curve and corresponding dispatch of installed generation in scenario 3; and (b) breakdown of installed capacity and generation of dispatchable generation technology in scenario 3.

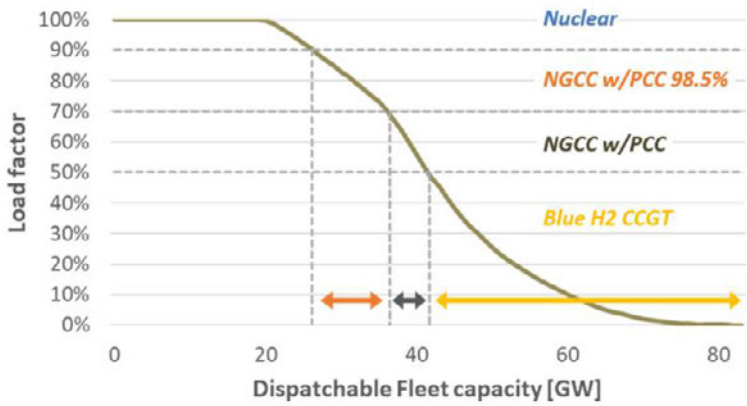


Figure 24: Load factor per incremental GW of the dispatchable fleet in scenario 3 along with load factor ranges of dispatchable technologies and subsequently deployed capacity per technology.

5.4.3 Scenario 4 – VRES with optimised dispatchable fleet

Within this scenario, we explore the requirements for dispatchable generation given an electricity grid with high penetration of renewables. We analyse the impacts of VRES on the required capacity and utilisation (load factors) for dispatchable generation, the installed capacity and utilisation for individual dispatchable technologies and the difference in costs for the system when moving from scenario 3 to scenario 4 through the incorporation of VRES.

5.4.4 Impact of VRES on required dispatchable capacity and its utilisation

In a future grid with high renewable penetration there is likely to remain a significant demand for dispatchable capacity. Variable renewable energy sources reduce the need for thermal generation but significant need for back up capacity is likely to remain.

In scenarios 4 and 5 with VRE, we assume a given installed GW capacity of wind and solar in the electricity system. We simulate the amount of generation of these plants in each hour of the modelled year (2035) using historical weather data (on solar irradiation and wind speeds). Subtracting the VRE generation from the demand in each hour delivers the net demand profile, which must be met by dispatchable capacity.

The addition of VRE to the system reduces the requirement for dispatchable generation by around 80% in terms of TWh. However, the requirement for dispatchable capacity is only reduced by around 20%. This is shown in Figure 25 such that VRE reduces the need for TWh of dispatchable generation (area above the x-axis) by 76% from 378 TWh to 92 TWh (left). However, the peak demand for dispatchable generation and thus the installed dispatchable capacity is only reduced by 12 % from 82 GW to 72 GW in scenario 4 and then further down to 65 GW through deployment and operation of batteries (corresponding to a 21% reduction from 82 GW).

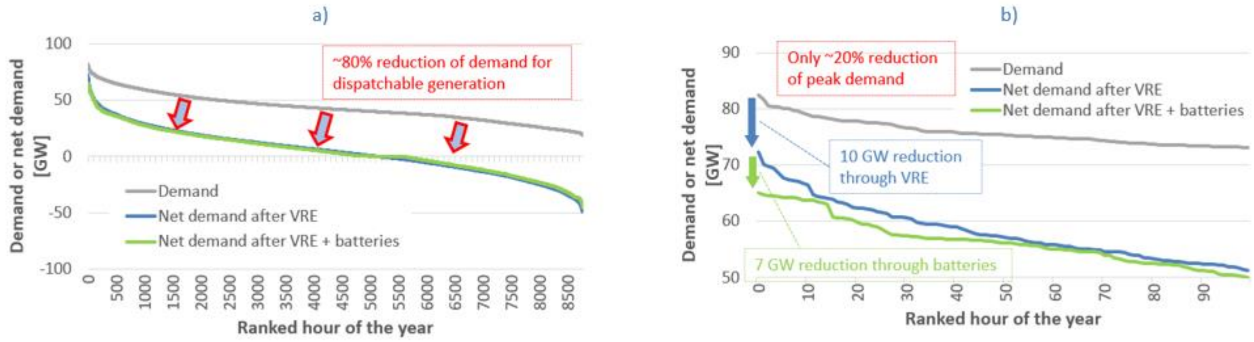


Figure 25: Load duration curve in scenario 3, net load duration curve in scenario 4 and in scenario 5 after operation of battery storage; (a) the full annual curve and (b) the curve for only the 100 hours of highest load/net load.

While a high requirement for dispatchable capacity will remain in a highly renewable system, this capacity will be utilised at a much lower rate than in a system without renewables. This is shown in Figure 26. The range of load factors of dispatchable plants is significantly reduced when adding VRE: the maximum load factor of dispatchable capacity drops from 100% in scenarios 1-3 to 58% in scenario 4 (left). The average load factor of all dispatchable capacity is reduced from 52% in scenarios 1-3 to 14% in scenario 4 (right). Adding VRE eliminates need for baseload plants while increasing need for peaking plants (right). We define baseload plants to have a load factor >70%, mid merit plants to have a load factor >10% and <70%, and peaking plants to have a load factor <10%.

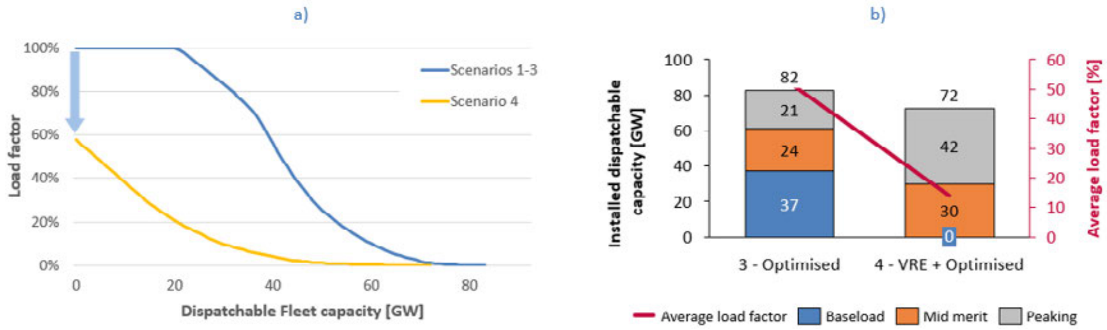


Figure 26: (a) Load factor per increment of dispatchable fleet capacity in scenarios 1-3 vs 4; (b) breakdown of dispatchable capacity into baseload, mid merit, and peaking capacity in scenarios 1-3 vs 4.

5.4.5 Installed capacity per technology and its operation

As observed in chapter 4 above, at low load factors, H2CCs are more economic than natural gas fired NGCCs with post combustion CO_2 capture due to the lower CAPEX excluding the cost of blue hydrogen generation plants which will be required for other services such as industrial, heat and transport decarbonisation. Subsequently we see mostly H2CCs deployed in the scenarios with VRE due to the low load factors of dispatchable generation while no nuclear capacity is deployed and only a small amount of NGCCs with post combustion capture.

This can be seen in Figure 27, illustrating installed capacities and their operation in scenario 4. The total installed dispatchable capacity amounts to 72 GW[77]. Chapter 4 concluded that NGCC w/PCC with 98.5% capture rate is only competitive at load factors above 70% and nuclear only at load factors above 90%. As the maximum load factor of dispatchable plants in this scenario is 58%, no nuclear or NGCC w/ PCC 98.5% are deployed (a). Blue H2CCs provide ~90% of dispatchable generation capacity and ~80% of all dispatchable

[77] Hardly visible in the graph as several GW of capacity are only utilised for a few hours in the year

generation corresponding to 19% of demand (b). Power CCS generation covers 91TWh, 24% of demand, a reduction by 53 TWh compared to scenario 3.

Figure 28 shows the load factor per increment of the dispatchable fleet along with the load factor ranges of dispatchable technologies from chapter 4, which determine the installed capacity per technology.

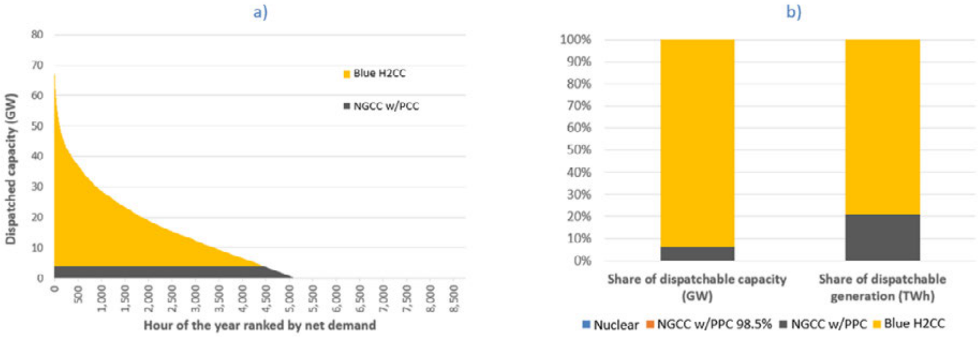


Figure 27: (a) Load duration curve and corresponding dispatch of installed generation in scenario 4; and (b) breakdown of installed capacity and generation of dispatchable generation technology in scenario 4.

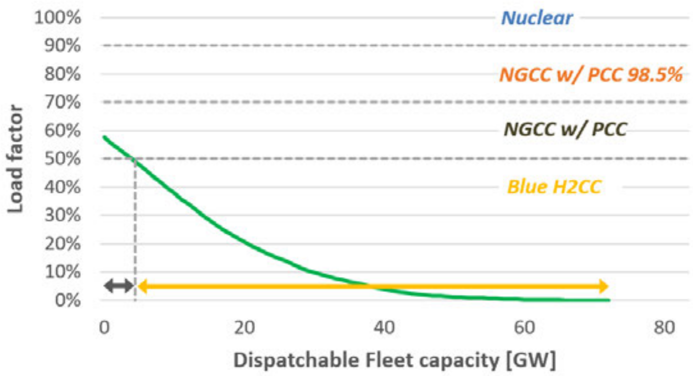


Figure 28: Load factor per incremental GW of the dispatchable fleet in scenario 4 along with load factor ranges of dispatchable technologies and subsequently deployed capacity per technology.

5.4.6 Cost comparison of scenario 3 and 4

While deployment of variable renewable energy requires a much higher total generation capacity to be installed, it still enables lower total generation costs. This is since technologies deployed in scenarios with variable renewable energy have lower CAPEX per MW capacity installed.

Figure 29 (a) shows total installed generation capacity (non-dispatchable and dispatchable) in scenarios 3 and 4 along with total annual generation costs. Total installed capacity (including VRE) in scenario 4 is more than twice as high as in scenario 3. This is due to the fact that variable renewable energy plants need to be complemented with back up capacity as illustrated in Figure 29. However, despite the significantly higher generation capacity installed, the overall system costs are reduced by 6% in scenario 4 compared to scenario 3; CAPEX are also reduced (b). This is due to the fact that the technologies deployed in scenario 4 are on average cheaper to build; in more detail the CAPEX per MW of installed capacity is lower for the main technologies deployed in scenario 4 (wind, solar, Blue H2CC) than those in scenario 3 (nuclear, NGCC w/PCC, NGCC w/PCC 98.5%).

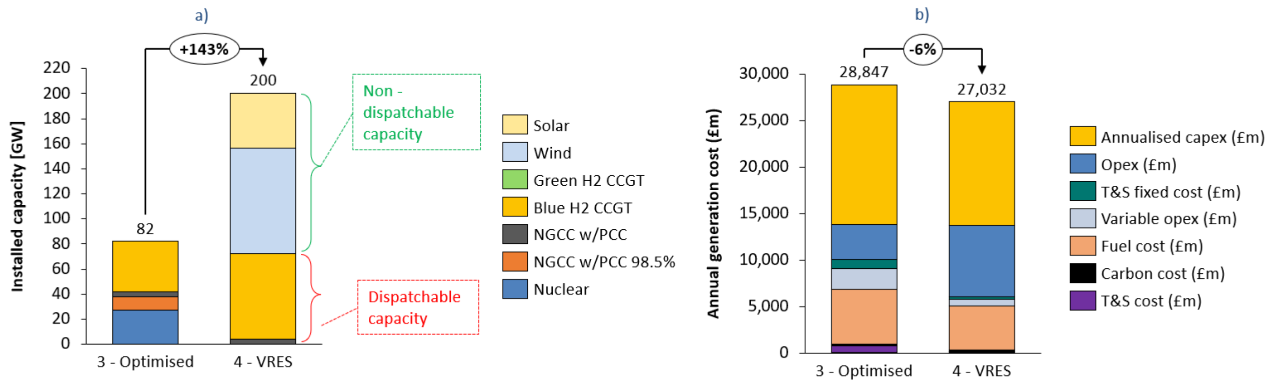


Figure 29: (a) Installed generation capacities (VRE and dispatchable) in scenarios 3 and 4; and b) total generation costs in scenarios 3 and 4.

5.4.7 Scenario 5 – VRES with storage and optimised dispatchable fleet

Within this scenario, we explore the requirements for dispatchable generation given an electricity grid with high penetration of renewables and the incorporation of storage options such as green H2CCs and battery storage. We analyse the installed capacity and utilisation for individual dispatchable technologies as well as those for battery and H2P2P.

5.4.8 Installed capacity per technology and its operation

Figure 30 shows installed dispatchable generation capacities and their operation in scenario 5. Within this scenario 8.7 GW of battery storage is deployed with a corresponding average duration of 6 hours. This battery storage provides 47.8 GWh or approximately 10% of dispatchable capacity. Within the modelling, a roundtrip efficiency of 85% is assumed which limits the discharge of a battery from 8.7 GW to 7.4 GW. For dispatchable generation capacity, the majority is split between green H2CC and blue H2CC, both being approximately 40%. However, blue H2CCs provide most of the dispatchable generation (64 TWh, ~75%), whereas Green H2CCs only provide a minor fraction (4.3 TWh, 5%). Power CCS provides 81TWh which is approximately 22% of demand, which is 10TWh less than that observed in scenario 4.

Figure 31 shows the load factors of any dispatchable capacity in this scenario are below 60%. Therefore, no capacity of natural gas fired power plants with higher capture rate or nuclear generation is deployed, as these capacities are only considered cost optimal at load factors above 70% and 90% respectively.

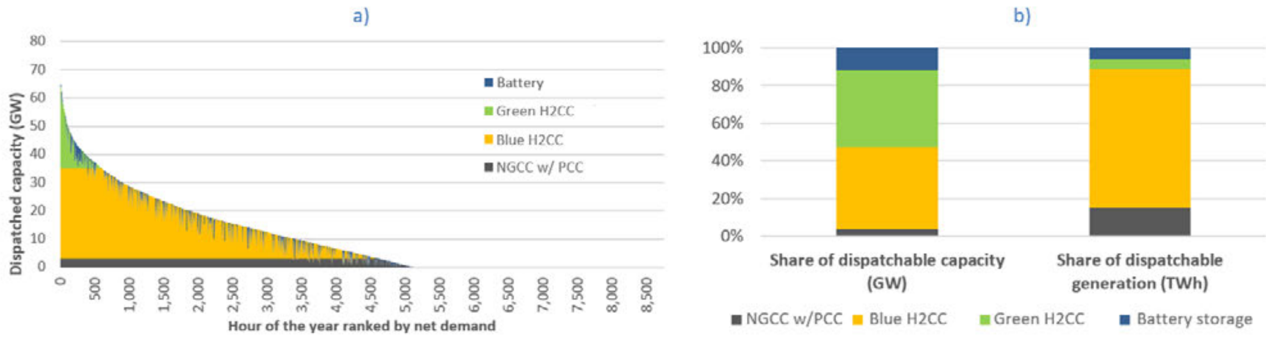


Figure 30: (a) Load duration curve and corresponding dispatch of installed generation in scenario 5; and (b) breakdown of installed capacity and generation of dispatchable generation technology in scenario 5.

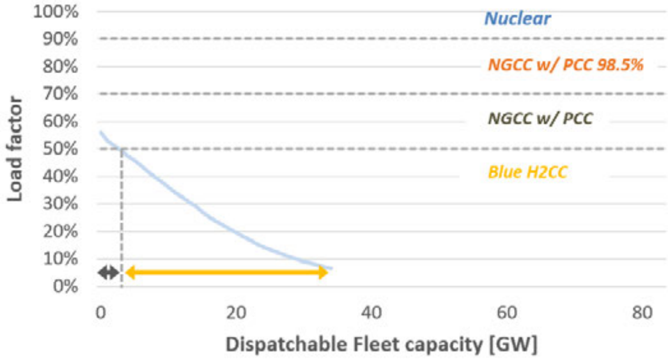


Figure 31: Load factor per incremental GW of the dispatchable fleet (excluding battery and green H2CCs) in scenario 5 along with load factor ranges of dispatchable technologies and subsequently deployed capacity per technology.

5.4.9 Operation of battery and H2P2P storage

In scenario 5, the same VRE capacities are deployed as in scenario 4. However, battery and H2P2P storage are deployed to store VRE generation which would otherwise be curtailed and dispatch it at times of high net demand. This increases the amount of VRE generation that is utilised and subsequently VRE penetration. On the other hand, demand for generation from dispatchable generation not linked to VRE generation (i.e. from Blue H2CCs, NGCCs w/ PCC, or nuclear plants) is reduced.

This reduction of demand for dispatchable generation is illustrated in Figure 32 which shows net demand after VRE generation, then after subsequent application of battery storage, and after operation of H2P2P storage. In our model batteries have priority dispatch, i.e. they are dispatched before any other dispatchable generation to meet any non-zero net demand. This is since they are expensive to build and are thus deployed with limited energy storage (MWh) capacity. Subsequently they get fully charged quickly and need to be discharged as quickly as possible to make them available again for charging. As discussed earlier, H2P2P on the other hand is cheap to build but expensive to use due to its low roundtrip efficiency. Green H2CCs using green H2 produced by the H2P2P storage are thus dispatched last in the dispatch order for the dispatchable fleet in our model. This is illustrated in Figure 32 such that when adding H2P2P, positive net demand is reduced in the hours of highest net demand (red dotted line at the left of the graph). However, in hours when the positive net demand is lower than 35 GW, the addition of H2P2P does not change the net demand. For in this case the net demand is met by the remaining dispatchable fleet.

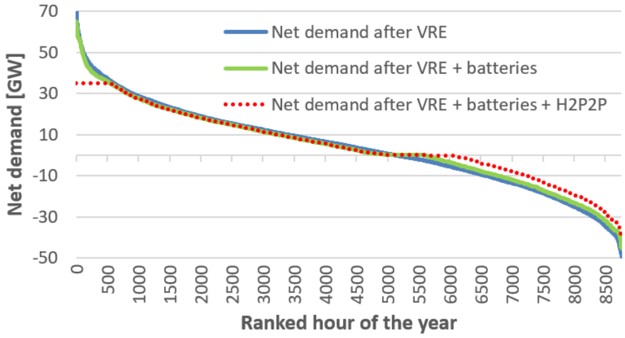


Figure 32: Net demand after VRE, VRE and battery storage, and VRE and battery storage and H2P2P storage.

Deployment of battery and H2P2P storage in scenario 5 reduces curtailment by 33% (18 TWh), see Figure 33, (a). This reduces the curtailment rate of the installed VRES capacity from 16% to 11%. About two thirds of the curtailment reductionis achieved by electrolysers producing green H_2, the remaining third by battery storage, see Figure 33 (b). [78]

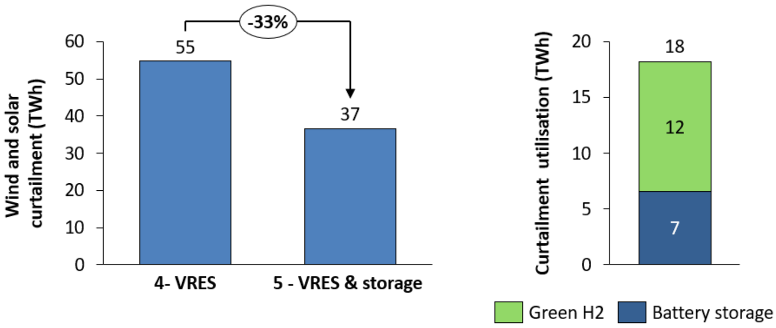


Figure 33: (a) Curtailment reduction by batteries and (b) H2P2P storage in scenario 5.

While batteries are dispatched almost on a daily basis in the model due to the mentioned priority dispatch, green H2CCs are utilised only on days of system stress in the winter, which can seen in Figure 34. The reason behind this is the underlying net demand profile after application of battery storage, which is shown in Figure

[78] Electricity curtailment could further be reduced with DSR measures, including operation of H2 electrolysers for uses other than power generation, such as for use as a feedstock for industry. This is not covered within the modelling.

35. This shows that 20 GW of the dispatchable plant capacity is only used on 20 days of the year, i.e. is run at extremely low load factors.

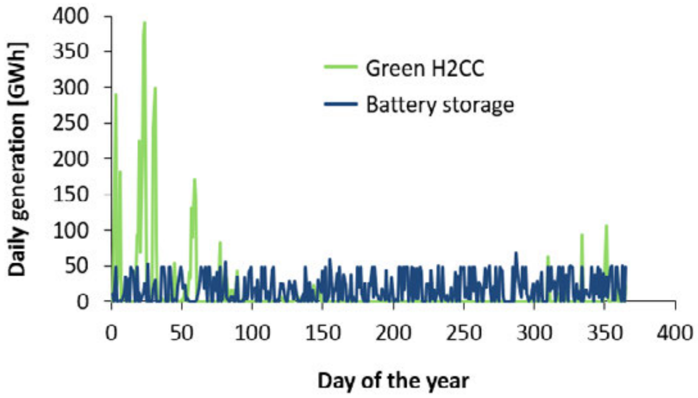


Figure 34: Daily generation of batteries and Green H2CCs in scenario 5.

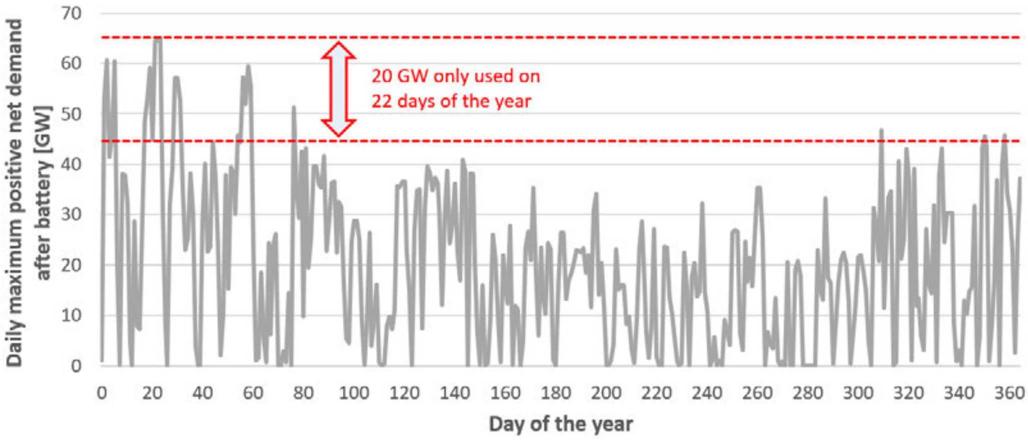


Figure 35: Daily maximum positive net demand after battery dispatch in scenario 5.

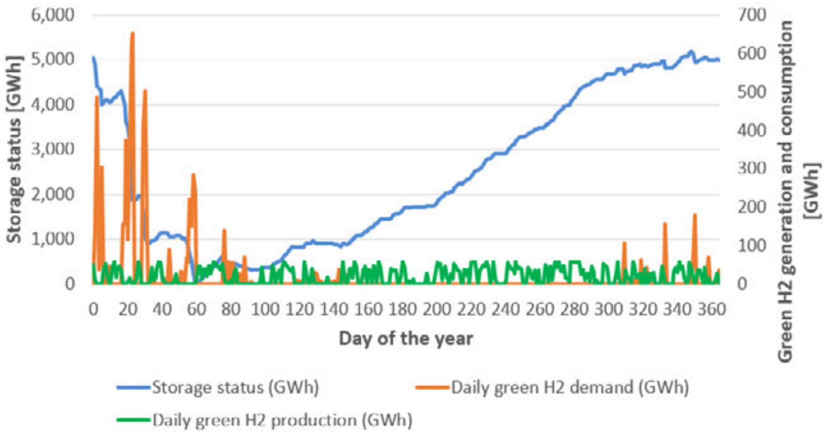


Figure 36: Daily green H2 production by electrolysers and consumption by Green H2CCs along with hydrogen storage status (amount of H2 stored).

The daily production of green H2 in electrolysers belonging to the H2P2P system, the consumption of green H2 in green H2CCs, as well as the status of the H2 storage of the H2P2P system are shown in Figure 36. The electrolyser capacity is chosen by the model as the minimum capacity which is sufficient to generate the annual H2 demand of the green H2CCs, given the annual renewable curtailment profile of the system. The storage is sized by the model at a size sufficient to balance the supply and demand of H2 of the H2P2P system. This results in an electrolyser capacity of 4 GW and a H2 storage size of 5.2 TWh for the H2P2P system. The electrolyser capacity is operated at a 34% load factor.

5.5 Discussion of modelling results

The modelling within this report is based on important assumption and caveats which present uncertainties to the results, which are listed below:

- **The VRE penetration is an exogenous input and not optimised:** The penetration could increase from the projected ~75% in 2035 further to perhaps 90% in 2050. A higher VRE penetration would reduce the generation by power CCS technologies in the system. A higher VRE penetration would furthermore increase the benefits of storage to the system and might thus lead to a higher deployed storage capacity in the model.
- **The benefits of storage on network savings have not been included:** Network costs savings which energy storage can provide have not been accounted for in the analysis. Accounting for such benefits would increase the installed storage capacity in the model.
- **The cost for Blue H2 does not change depending on its utilisation:** This is based on an assumption of a liquid market for blue H2 allowing power plants to purchase blue H2 according to their varying demand at a stable price. However, if the power plant was procuring blue H2 from a production facility dedicated to a large extent to this power plant, the price of blue H2 might increase in case of lower utilisation of the blue H2 production facility due to fixed cost (capital investment and maintenance).
- **Green H2 production would not be limited to curtailed generation only:** Green H2 for use in power plants could also be produced by dedicated VRES (rather than only from otherwise curtailed output of VRES plants supplying power directly to the electricity system as in our modelling).
- **The costs for future technologies are still an uncertainty:** There are significant uncertainties around the future costs of technologies, in particular those of still commercially immature technologies such as power plants with post combustion CO_2 capture and new nuclear reactors. Given such uncertainties and the relatively small cost differences of scenarios 3-5, these scenarios can be seen as having similar generation costs.

  Results are highly sensitive to assumed fuel prices: A higher assumed price for natural gas would increase total cost in scenario 3 significantly but only have limited impact on costs in scenario 4 where the majority of generation is provided by VRE. Thus, a higher natural gas price would increase the savings of scenarios with renewables (scenario 4 and 5) compared to scenarios without them (scenarios 1-3).

5.6 Recommendations for future work

Recommendations for future work include the following:

- This report assumes completely new build data and does not account for any pre-existing generators within the UK. Incorporating pre-existing power assets which will be retired over time or reasonably retrofitted with CCS could be a valuable piece of future work, focusing on specific geographies (such as the GB power system).
- This report accounts for the increase in electricity demand as other sectors electrify to decarbonise. However, security of supply was out of scope. Our analysis ensures that there is sufficient capacity to meet the demand in an average year but does not explore extreme system stress events or other security of supply considerations. Considerations for the cross-sectoral effects of the energy transition and the necessity for security of supply regarding electric power, heating, fuels and feedstock for households, industry, and traffic according to the fluctuating demand would result in a more wholistic picture of the energy system.
- Considerations into the security of supply beyond that required to meet the net demand in the reference year, such as incorporating the supply cost of secure electricity for society, would lead to a more realistic picture for the electricity system. Additionally, the analysis does not account for the

spatial constraints and network representations of an electricity grid. Modelling of these elements would be required to assess the cost of grid expansion and the total system cost under different generation mixes. We thus recommend exploring these aspects in future studies on this topic.

- Investigation into the use of VRES for powering electric vehicles, thermal storages and heat pumps is with an application of thermal storages, electric heat generation and heat pumps for solvent regeneration in post-combustion capture plants.This report does not incorporate DSR measures or the use of interconnectors. This is conservative, as both DSR and interconnectors can reduce the need for dispatchable generation or for BESS. Incorporating DSR and use of interconnectors into the model can be a valuable piece of future work.

6. Conclusions

This study sought to assess CCS costs and integrate these insights into a techno-economic analysis of power CCS and other power generation options to explore the role that power CCS technologies could play in the generation mix of a largely decarbonised power system.

Firstly, an LCOE model was developed to explore the costs for dispatchable generation for 2025, 2030 and 2035, respectively. From this modelling, we have found that battery storage is optimal to provide dispatchable generation for low load factors while nuclear provides baseline power to meet baseline demand. For load factors between 30 and 85% there is a mixture of blue H2, and natural gas with CCS at varying capture rates, thus showing that the role of natural gas with carbon capture is optimal in terms of cost when providing dispatchable generation for load factors between 50-85%.

Secondly, the results from the modelling and assumptions used demonstrated that:

- **A power system based on VRE, and one based on dispatchable low carbon generation only could have similar annual generation costs.** Despite the higher capacity requirement and low load factors of the dispatchable fleet, a system with high VRE penetration has similar or even slightly lower generation cost than one based on dispatchable generation technologies only. In such a system blue H2CCs would be the most economic Power CCS[79] technology due to their lower CAPEX compared to post combustion capture plants.
- **Power CCS technologies could provide flexibility to the power system in form of dispatchable power generation.** Power systems which don't include VRES and those which do include VRES both include power CCS as a cost-effective technology option to provide flexible generation for supporting power systems.
- **Nuclear power provides the most significant proportion of the generation.** In a cost efficient system based on dispatchable generation, nuclear power is a key technology operating t high load factors above 85%. A wide range of power CCS technologies, including NGCCs with post combustion capture, could play a role in such a future power system complementing nuclear generation.
- **The VRE penetration has been fixed in this report as an exogenous assumption.** Further analysis varying the VRE penetration would provide additional insight on the cost optimal mix of generation mix in a zero-carbon power system. We thus recommend exploring this in future studies on this topic.
- **Systems with and without VRES require similar amounts of dispatchable generation capacity.** Sufficient dispatchable generation capacity could thus be a key enabler to achieve high VRE penetration while ensuring security of supply. However, this dispatchable generation capacity is utilised at much lower rates than in a system without VRE generation.

[79] CAPEX investment in carbon capture would also be required for the production of blue H2 which utilises Steam Methane Reforming of natural gas. However as mentioned in section 5.5, we assume that a high liquidity of the hydrogen market on the demand as well as the supply side in combination with availability of hydrogen storage means that production capacities are utilised at high rates regardless of fluctuations of demand in some segments of the market. Therefore, we assume blue H2CCs can purchase H2 at a stable price regardless of their intermittent operation during the year.

- **The load factors for dispatchable fleets are low within a system with high VRES.** The average load factor[80] of the dispatchable fleet in a system with high VRE penetration is below 15%. The required generation capacity (dispatchable generation and VRE generation) in such a system is more than twice as high as the capacity in a system without VRE.
- **Blue H2CC is still required when batteries and H2P2P are deployed.** A significant requirement for dispatchable generation remains when batteries and H2P2P is deployed as flexible generation options. A cost-effective way to provide the additional required flexibility is to deploy blue H2CCs.
- **The future generation mix will not focus purely on costs.** Decisions on the future power generation mix and the choice between blue and green H2 will take into account not only costs but also wider policy drivers such as reduction of reliance on energy imports as well as environmental (e.g. upstream natural gas emissions) and supply chain concerns (e.g. current Chinese dominance in battery and PV supply chains as well as increased reliance of clean energy technology on critical materials compared to fossil fuels based technology[81]).
- **Storage and flexibility are not limited to batteries and H2CC alone.** Higher VRE penetration as well as DSR from EVs and heat pumps might improve the case for battery storage and green hydrogen and could reduce the opportunity for power CCS plants.

[80] Load factor is defined as the ratio of the amount of electricity produced by a wind farm to its total potential, based on nameplate capacity, over a period of time. Source: Potential to improve Load Factor of Offshore Windfarms in the UK to 2035, DNV (2019)

[81] https://iea.blob.core.windows.net/assets/a86b480e-2b03-4ergy 25-bae1-da1395e0b620/EnergyTechnologyPerspectives2023.pdf.

7. References

(n.d.). Retrieved from https://www.ice.org.uk/knowledge-and-resources/case-studies/sleipner-carbon-capture-storage-project

Hailong Li et al. (2011). Impacts of exhaust gas recirculation (EGR) on the natural gas combined cycle integrated with chemical absorption CO2 capture technology. Energy Procedia, 1411-1418.

Institute for Energy Economics and Financial Analysis. (2022). The ill-fated Petra Nova CCS project: NRG Energy throws in the towel. Retrieved April 2023

International CCS Knowledge Center. (2018). The Shand CCS Feasibility Study.

International Energy Agency. (2021). World Energy Outlook 2021.

International Energy Agency. (2022). World Energy Outlook 2022.

Agency, I. E. (2022). World Energy Outlook 2022. IEA.

Australian Academy of Science. (n.d.). How a battery works. Retrieved April 2023

BEIS. (2018). Assessing the Cost Reduction Potential and Competitiveness of Novel (Next Generation) UK Carbon Capture Technology. BEIS.

BEIS. (2018). Assessing the Cost Reduction Potential and Competitiveness of Novel (Next Generation) UK Carbon Capture Technology, Benchmarking State-of-the-art and Next Generation Technologies.

Bester. (n.d.). Development stages of renewable energy projects . Retrieved April 2023

Cadent. (2018). HyNet North West, From Vision to Reality.

Carbon Capture & Sequestration Technologies. (n.d.). Boundary Dam Fact Sheet: Carbon Dioxide Capture and Storage Project. Retrieved April 2023

Coal Industry Advisory Board Submission to the International Energy Agency. (2018). Learning by doing: The cost reduction potential for CCUS at coal-fired power plants.

Dean et al (2011). The calcium looping cycle for CO_2 capture from power generation, cement manufacture and hydrogen production. Chemical Engineering Research and Design, 89 (6).

Department for Business, E. &. (2021). Project Whitehall: Net Power Allam-Fetvedt Cycle Power Plant for UK Deployment .

DNV GL Energy. (2019). Potential to improve Load Factor of offshore wind farms in the UK to 2035.

Global CCS Institute. (2022). Global Status of CCS.

IEA. (2020). Projected costs of generating electricity.

IEA. (2021). Global Hydrogen Review 2021.

IEA (2023). International Energy Perspectives 2023.

IEAGHG. (2019). Towards Zero Emissions CCS from Power Stations using Higher Capcture Rates or Biomass .

IEAGHG. (2019). Towards zero emissions CCS with biomass or higher capture rates.

IEAGHG. (2020). Update Technoeconomic Benchmarks for Fossil Fuel-Fired Power Plants with CO2 Capture.

International Energy Agency . (2021). Net Zero by 2050, A Roadmap for the Global Energy Sector.

Kallanish Commodities. (2020). Battery pack prices derail trend in 2022: BNEF. Retrieved April 2023

Michael Schimpe et al. . (2017). Energy efficiency evaluation of a stationary lithium-ion battery container storage system via electro-thermal modeling and detailed component analysis. Applied Energy.

MTR. (2022). Other Industrial Plants . Retrieved April 2023

National Energy Technology Laboratory. (2019). Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity.

National Energy Technology Laboratory. (2021). Bituminous Coal and Natural Gas to Electricity: >90% Capture Cases Technical Note.

National Energy Technology Laboratory. (2021). Technoeconomic and Life Cycle Analysis for Bio-Energy with Carbon Capture and Storage (BECCS) Baseline.

National Renewable Energy Laboratory. (2021). Cost Projections for Utility-Scale Battery Storage: 2021 Update.

Power Engineering. (2017). Petra Nova: An Evolutionairy Project. Retrieved April 2023

Power Engineering. (2017). World's Largest Post-Combustion Carbon Capture Facility Completed. Retrieved April 2023

Schmidt, O. (2018). Future cost of electricity storage and impact on competitiveness.

Stavroula Giannaris et al. (2018). SaskPower's Boundary Dam Unit 3 Carbon Capture Facility - The Journey to Achieving Reliability. 15th International Conference on Greenhouse Gas Control Technologies, GHGT-15.

Tanaka, H. (2018). Advanced KM CDR Process using New Solvent. 14th International Conference on Greenhouse Gas Control Technologies, GHGT-14 .

The Factorial Method of Cost Estimation. (2023). Retrieved from Chemical Engineering Projects:

https://chemicalprojects.wordpress.com/tag/lang-factor/

Schimpe, Michael, Naumann, Maik, Truong, Nam, Hesse, Holger C., Santhanagopalan, Shriram, Saxon, Aron, & Jossen, Andreas. (2017) Energy efficiency evaluation of a stationary lithium-ion battery container storage system via electro-thermal modeling and detailed component analysis. United States. https://doi.org/10.1016/j.apenergy.2017.10.129

Stephenne et al., 2022. Recent Improvements and Cost Reduction in the CANSOLV CO2 Capture Process. Proceedings of the 16th Greenhouse Gas Control Technologies Conference (GHGT-16).

XODUS Group. (2020). Porthos CCS - Transport and Storage Tariff Review.

IEA Greenhouse Gas R&D Programme

ieaghg.org
+44 (0)1242 802911
mail@ieaghg.org

IEAGHG, Pure Offices, Cheltenham Office Park,
Hatherley Lane, Cheltenham, GL51 6SH, UK

IEAGHG