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A REVIEW OF COST ESTIMATES FOR CARBON CAPTURE AND STORAGE IN THE POWER SECTOR

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INTERNATIONAL CENTRE FOR
SUSTAINABLE CARBON

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PREFACE

This report has been produced by the International Centre for Sustainable Carbon (ICSC) and is based on a survey and analysis of published literature and on information gathered in discussions with interested organisations and individuals. Their assistance is gratefully acknowledged. It should be understood that the views expressed in this report are our own and are not necessarily shared by those who supplied the information, nor by our member organisations.

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The overall objective of the International Centre for Sustainable Carbon is to continue to provide our members, the International Energy Agency (IEA) Working Party on Fossil Energy and other interested parties with definitive and policy relevant independent information on how various carbon-based energy sources can continue to be part of a sustainable energy mix worldwide. The energy sources include, but are not limited to coal, biomass and organic waste materials. Our work is aligned with the UN Sustainable Development Goals (SDGs), which includes the need to address the climate targets as set out by the United Nations Framework Convention on Climate Change. We consider all aspects of solid carbon production, transport, processing and utilisation, within the rationale for balancing security of supply, affordability and environmental issues. These include efficiency improvements, lowering greenhouse and non-greenhouse gas emissions, reducing water stress, financial resourcing, market issues, technology development and deployment, ensuring poverty alleviation through universal access to electricity, sustainability, and social licence to operate. Our operating framework is designed to identify and publicise the best practice in every aspect of the carbon production and utilisation chain, so helping to significantly reduce any unwanted impacts on health, the environment and climate, to ensure the wellbeing of societies worldwide.

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ABSTRACT

Carbon capture and storage frequently features heavily in lowest-cost decarbonisation pathways for society, and has received growing attention as ‘net zero’ carbon emissions become a widespread policy goal. At the same time, the technology has been hindered by the perception of high costs at the plant level, particularly in the power sector, where wind and solar power offer much more competitive costs on a levelised cost of electricity (LCOE) basis. In recent years, there has been a trend towards developing new cost metrics which better represent the characteristics of different generation sources in a viable electricity grid, thereby highlighting the need for dispatchable power plants to complement intermittent renewable sources. Using such metrics, including levelised avoided cost of electricity (LACE) and value-adjusted LCOE (VALCOE), a more accurate determination of the value to grid decarbonisation of gas- or coal-fired power plant equipped with carbon capture and storage (CCS) can be obtained. However, for highly decarbonised or net zero scenarios, a more rigorous assessment is offered by a total system cost analysis, in which a grid model determines total costs under operational reliability constraints. This analysis highlights that the value of CCS in reducing total grid decarbonisation costs can only become apparent at high levels of renewable penetration (80–90%), at which point, the absence of the technology can result in exponential cost escalation.

ACRONYMS AND ABBREVIATIONS

A/R	afforestation/reforestation
BAU	business as usual
BECCS	bioenergy carbon capture and storage
CCGT	combined cycle gas turbine
CCS	carbon capture and storage
CCUS	carbon capture utilisation and storage
CFBC	circulating fluidised bed combustion
CSP	concentrated solar power
DACCS	direct air carbon capture and storage
DOE	Department of Energy, USA
EIA	Energy Information Administration, USA
EOR	enhanced oil recovery
EU	European Union
FOAK	first of a kind
GCCSI	Global CCS Institute
ICSC	International Centre for Sustainable Carbon (formerly IEA Clean Coal Centre, IEACCC)
IEA	International Energy Agency
IEAGHG	IEA Greenhouse Gas R&D Programme
IGCC	integrated gasification combined cycle
IRCC	integrated reforming combined cycle
LACE	levelised avoided cost of electricity
LCOE	levelised cost of electricity
LTO	long-term operation
NEM	National Energy Market, Australia
NETL	National Energy Technology Laboratory, USA
NOAK	nth of a kind
OCGT	open-cycle gas turbine
OECD	Organisation for Economic Co-operation and Development
O&M	operation and maintenance
PV	photovoltaics
SC	supercritical
SCoRE	System Cost of Replacement Energy
T&S	transport and storage (of CO ₂)
TSC	total system cost
USC	ultrasupercritical
VALCOE	value-adjusted levelised cost of electricity
VRE	variable renewable energy
ZEP	Zero Emissions Platform

Note: all monetary values are in United States dollars (\$) unless otherwise stated. Exchange rates are from August 2021 (average rate) unless otherwise stated.

UNITS

Gt	gigatonnes
km	kilometre
MBtu	million British thermal units
MW	megawatt
MWh	megawatt-hour
MWth	megawatt thermal
t	tonne
tCO ₂	tonnes of CO ₂ equivalent
TW	terawatt

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EXECUTIVE SUMMARY

THE ROLE OF COST ANALYSIS IN GRID DECARBONISATION

Carbon capture and storage (CCS) frequently features in lowest-cost decarbonisation pathways and has therefore received growing attention as net zero carbon emissions become a widespread policy goal. At the same time, wider deployment of this technology has been hindered by the perception of high costs at the plant level, particularly for applications in the power sector, where wind and solar power are more competitive on a levelised cost of electricity (LCOE) basis. Cost analysis is an important tool for project developers, investors, and grid planners in identifying the most economically viable sources of low-carbon power generation, as well as for enabling researchers to assess newly developed technologies. However, there is growing recognition that costing the generation of electricity alone may have limited value for determining the optimum portfolio of technologies in a decarbonised grid. A deeper analysis of technology cost – and value – at net zero can help elucidate why several countries continue to pursue the use of CCS in the power sector.

THE COST OF ELECTRICITY FROM CCS POWER PLANTS

Owing to inconsistent methodologies and variation in input assumptions, estimates of LCOE can show considerable variation for the same technology – particularly for those which have not reached widespread deployment, such as CCS. Based on a review of some ‘bottom up’ techno-economic studies, the LCOE of new supercritical coal plant with post-combustion CCS is typically found in the range of 90–130 \$/MWh for locations in the USA and Western Europe, while combined cycle gas turbines (CCGT) with CCS are in the range 70–100 \$/MWh. Lower LCOEs for coal-based CCS (in the range 80–100 \$/MWh) have been estimated for China, which is one of the few regions examined where CCGT-CCS appears more costly on this basis. In the absence of carbon pricing, building a new coal or gas plant with CCS tends to incur a 70–100% increase in LCOE relative to a new ‘unabated’ plant of the same type. Retrofitting CCS to an existing power plant is a lower-cost option, but there is considerable variation in how LCOE is calculated for these cases.

Based on the few studies which have consistently examined different low-carbon generation, LCOEs of coal-CCS and CCGT-CCS are generally 1.5–3 times higher than those of solar power and onshore wind in OECD countries. Offshore wind shows more regional variation, with costs similar to those of onshore wind in Northern Europe but higher than CCS power plant in the USA.

In recent years, there has been a trend towards developing ‘adjusted’ LCOE variants which better account for other characteristics valuable to the grid, such as flexibility and dependable capacity. Such methods include value-adjusted LCOE (VALCOE), levelised avoided cost of electricity (LACE), and enhanced LCOE. Using these metrics, the cost differential between intermittent sources and

CCS-equipped power plants reduces, but not significantly for the levels of renewable deployment generally considered (<50%).

THE COST OF CO₂ AVOIDED

Carbon abatement technologies such as CCS are also frequently assessed on the cost of capturing or ‘avoiding’ a tonne of CO₂. Studies of operating and planned full-scale coal-CCS plants indicate that the cost of capturing CO₂ is falling and is expected to be around 45 \$/t for the next generation of retrofit projects in North America. This decline is associated with learning-by-doing, economies of scale and modular construction, improved financing, and technology optimisation. However, the cost of CO₂ avoided – which accounts for the energy consumed by the capture process – generally falls in the range of 60–80 \$/t for new coal-CCS plant in high-income countries. CCGT-CCS appears slightly more costly on this basis due to the lower CO₂ intensity of the unabated plant. Analysis of existing coal plants in China has identified particularly low-cost opportunities for CCS retrofit, with CO₂ avoided costs as low as \$30/t. Accurate comparison of CO₂ abatement costs with other low-carbon generation is highly dependent on the choice of displaced generation.

FROM COST TO VALUE: TOTAL SYSTEM COST ANALYSIS

Total system cost analysis aims to express the total cost of delivering a reliable electricity grid across a range of representative weather and demand scenarios, including all investment and operational costs over the course of the transition to lower carbon intensities. This method is increasingly useful for elucidating the value of potentially low-output, dependable capacity such as CCS, nuclear, or electricity storage in grids with very high levels of intermittent sources. In this context, the ‘value’ of a given technology can be identified as the cost increase which would be incurred if the grid were decarbonised without that technology being available. This approach more closely represents the overall cost of grid decarbonisation to be met by consumers or taxpayers.

Analysis of several regional and national grids show that wind and solar power consistently offer the lowest-cost option for the initial stages of decarbonisation, but low-carbon dispatchable generation becomes extremely valuable as higher levels are approached (>80–90% reduction in gCO₂/kWh). Forms of CCS frequently offer the most economic option for this dispatchable generation, with the proportions of coal, gas, or biomass-fired plant depending on various local factors. For emerging economies with rapidly growing demand, constraints on the achievable rates of renewables deployment suggest a significant role for CCS-based power plants in reaching net zero emissions at lowest cost and on the shortest timescale.

1 INTRODUCTION

As a growing number of national governments and corporations set a long-term target of ‘net zero’ carbon dioxide (CO₂) or greenhouse gas emissions, there is increasing recognition of the significant contribution which carbon capture, utilisation and storage (CCUS) can make towards realising this goal. Energy system modelling of potential pathways to net zero consistently features large-scale deployment of CCUS over the coming decades, particularly where a rapid and lowest-cost transition is favoured (IPCC, 2018; IEA, 2020a, 2021). In a recent roadmap for the global energy sector, the International Energy Agency (IEA) projects that over 7.5 GtCO₂ will be captured annually by the time net zero carbon emissions are reached in 2050 (IEA, 2021).

The prevalence of CCUS in such scenarios can be attributed to the diversity of key services the technology can provide in a decarbonised economy, including a means of mitigating challenging CO₂ emissions from ‘hard-to-abate’ process industries such as cement and steel production; enabling low-carbon dispatchable power plants to complement intermittent wind and solar power; providing a competitive source of low-carbon hydrogen; and the capability to remove carbon from the atmosphere through direct air capture and bioenergy applications (IEA, 2020b).

Despite this well-established potential to lower the overall cost of decarbonisation to society, the upfront cost of installing carbon capture technology and deploying CO₂ storage infrastructure has often been perceived as excessive, hindering early development of the technology (Budinis and others, 2018). This perception is particularly prevalent in the case of electricity generation, where the steady fall in the cost of wind and solar power presents a ready alternative solution for achieving significant decarbonisation of the sector. Such cost comparisons are often made on the basis of a ‘levelised cost of electricity (LCOE)’ for alternative power generation technologies, which usually highlight a clear advantage for some forms of renewable energy.

However, there is growing acceptance that an exclusive focus on energy generation costs in technology assessments has limited applicability for a net zero electricity grid, as it ignores a range of essential grid attributes (Heptonstall and others, 2017; IEA, 2018). These include adequate dependable capacity to meet peak demand and flexible generation which can respond to sudden, unexpected changes in supply or demand. Provision of these non-energy services becomes more valuable at high levels of deployment of variable renewable energy (VRE) such as wind and solar power, whose weather-dependent output does not necessarily coincide with consumer demand. More recently developed metrics for assessing low-carbon technologies have therefore sought to better quantify the contribution of a new unit of generating capacity towards overall system costs (IEAGHG, 2020b; Byrom and others, 2021). This kind of holistic analysis can identify the low-carbon technologies which offer the best overall ‘value’ for various stages of grid decarbonisation, where value can be understood as an avoided cost to society.

Despite the rise of more rigorous energy system analyses, straightforward cost metrics like LCOE remain popular as readily comprehensible tools for use in wider policy and public energy debate, as well as an indicator of likely investment trends in the power sector. If the value of carbon capture and storage (CCS) to decarbonisation is to translate effectively into the deployment envisaged by ambitious climate mitigation scenarios, it will be helpful to establish a similarly direct means of communicating this value. Equally, climate and energy policy must find appropriate means of expressing system-level value in the form of incentives which can offset the upfront cost of CCS.

It is vital to note that cost analysis in the energy sector is notoriously fraught with challenges in obtaining accurate, consistent, and directly comparable results. There is often a significant lack of consistency between methodologies used by different organisations, in terms of project cost boundaries, cost inputs, and assumptions associated with financing, technological learning rates and other key parameters. Such challenges become all the more apparent when comparing different low-carbon technologies at widely varying levels of development and deployment.

This report reviews some of the most notable recent attempts to rigorously assess the cost and value of CCS deployment in the power sector, including analysis of generic new-build plants and retrofit costs based on specific power plant cases. Where possible, these results are also presented with equivalent analysis of other low-carbon energy sources for direct comparison. In addition to presenting conventional cost metrics such as LCOE and CO₂ avoided costs, there is particular focus on studies which have sought to account for more complex power system cost factors, either through adjusted LCOE or total system cost analysis. By providing an overview of the literature to date, this report aims to identify some key trends in CCS costs where clear consensus exists, while highlighting the value of a shift to a ‘whole system’ perspective when assessing the technology contributions to grid decarbonisation.

2 OVERVIEW OF CCS TECHNOLOGIES

This chapter provides a short introduction to the current status of carbon capture and storage technologies in the power generation sector, with particular attention to factors relevant to cost assessments.

2.1 CURRENT STATUS OF CCS

CCS describes the process of separating the CO₂ emitted by combustion or other industrial processes (capture), and then sequestering it in suitable geological formations (storage). Application of this technology to enhanced oil recovery (EOR), in which the CO₂ is injected into mature oil wells to boost production, has been established in North America since the 1970s. Large-scale dedicated CO₂ storage for the purpose of avoiding greenhouse gas emissions was first demonstrated at Norway's Sleipner offshore gas platform in 1996, where CO₂ is removed from natural gas and stored in a saline aquifer formation beneath the North Sea (IEA, 2016a). This began a period of growing international interest in CCS as a climate change mitigation solution, with a strong initial focus on application of the technology to coal-fired power plants. Despite several unsuccessful initiatives to demonstrate the technology at large scale, particularly in Europe, 28 commercial CCS facilities have been realised on various industrial processes around the world, capable of capturing a total of around 40 MtCO₂/y (GCCSI, 2021). However, only two of these are associated with power plants, both of which are coal fired: Boundary Dam 3 in Saskatchewan, Canada, which started in 2014, and Petra Nova in Texas, USA, commissioned in 2017. Like most current projects, both these facilities rely on revenues from CO₂ used for EOR, and the Petra Nova capture facility was mothballed due to low oil prices in 2020 (Lockwood, 2020).

Since around 2018, a resurgence of political and commercial interest in the large-scale deployment of CCS has occurred, giving rise to growth in the pipeline of planned projects (GCCSI, 2020). In the USA, this has been largely driven by the expansion of the '45Q' tax credit, which compensates projects on the basis of tonnes of CO₂ stored. In Europe, challenging decarbonisation targets such as 'net zero by 2050' have induced some governments to offer financial support packages to CCS infrastructure projects, usually aimed at linking regional 'clusters' of industrial emitters, such as Northern Lights in Norway, Porthos in the Netherlands, and the Northern Endurance Partnership in the UK. In OECD countries, much of this renewed interest has shifted the earlier focus on coal-fired power plants to industrial emissions from outside the power sector (including steel, cement, and chemical production), although gas- and biomass-fired power plants still feature in some national plans. In the coal power sector, there remains considerable potential for CCS deployment in China, where the announcement in 2020 of an ambition to obtain net zero carbon emissions by 2060 has also accelerated interest in CCS, including the progression of several large projects on coal-fired power plants (Lockwood, 2021a).

2.2 POST-COMBUSTION CAPTURE

Carbon capture technology has conventionally been categorised as pre-combustion – where coal is first gasified and hydrogen is separated from the syngas to fuel a gas turbine; post-combustion – where CO₂ is separated from standard power plant flue gases; and oxyfuel combustion – where the fuel is fired in a mix of oxygen and CO₂ to produce a more concentrated stream of CO₂. While all three routes are considered technically mature, only post-combustion capture has been demonstrated on full-scale power plants (at Boundary Dam 3 and Petra Nova) (IEAGHG, 2015; NETL, 2020). More specifically, both operational facilities and most planned CCS projects in the power sector use similar forms of a post-combustion capture process based on CO₂-binding amine solvents. This leading technology therefore forms the basis of the vast majority of CCS cost estimates for the power sector. Although solvent formulations and process designs can vary, solvent-based post-combustion capture technologies essentially introduce cooled flue gas (with contaminants such as sulphur oxides (SO_x), nitrogen oxides (NO_x), and particulates pre-removed) to a large absorption column in which CO₂ is removed by a liquid solvent (Figure 1). The solvent is then sent to a stripper column where it is heated – using steam from the power plant itself or a separate cogeneration unit – to release a pure stream of CO₂. In addition to the Shell Cansolv technology used at Boundary Dam 3 and the Mitsubishi technology (Advanced KM CDR™) used at Petra Nova, other major suppliers of capture solvents include Fluor (Econamine FG Plus), Linde (BASF Blue), ION Clean Energy (ALAS), and Carbon Clean (CDRMax).

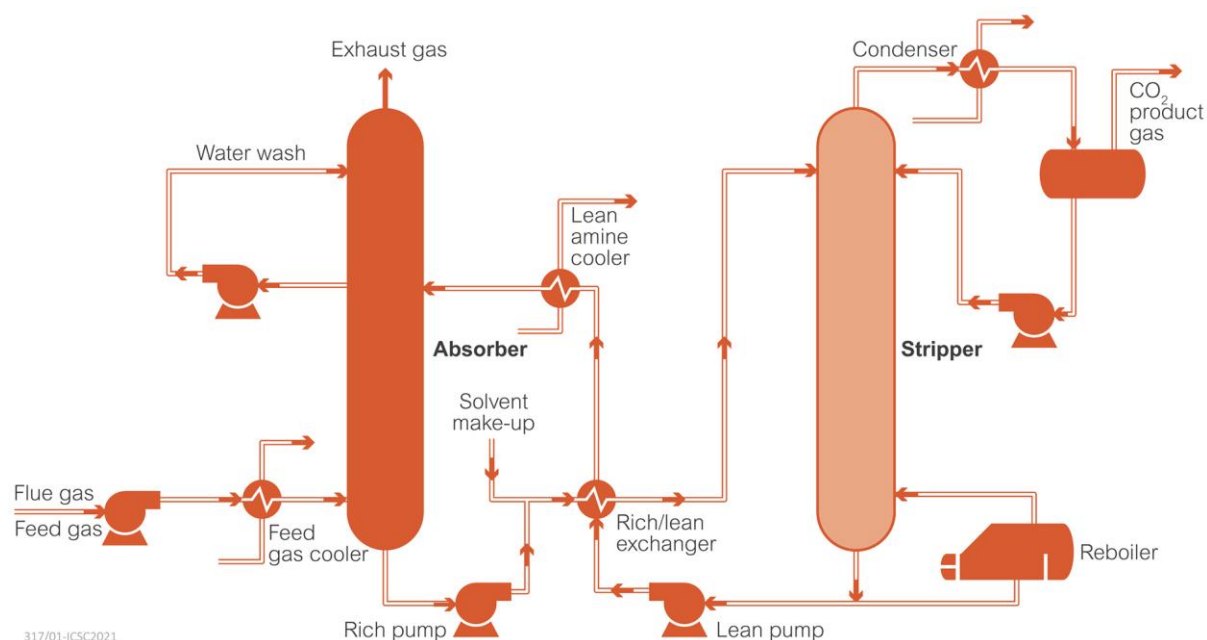


Figure 1 Schematic of a generic solvent-based post-combustion capture process

Post-combustion CO₂ capture technology can either be incorporated into the design of new power plants or retrofitted to existing units. Given the large scale (>2 TW) of the existing global coal fleet, retrofit applications have generally attracted the most attention, but the technical feasibility and cost

of retrofits depend to a great extent on various characteristics of the target plant. In addition to basic requirements for sufficient space and ideally, good existing pollutant controls, there are considerations about how best to thermally integrate the capture plant with the existing coal plant. In North America there is interest in minimising interference with the power plant steam cycle by sourcing power and steam from a dedicated gas-fired cogeneration unit – a format employed by the Petra Nova project. However, most CCS cost studies adopt the more conventional approach (used at Boundary Dam 3) of extracting steam from the crossover between the intermediate pressure and low-pressure turbines (Lucquiaud and Gibbins, 2011). Some modification of the turbine may be required to minimise efficiency losses, but a feasibility study conducted for Canada’s Shand plant has demonstrated that retrofit of a modern supercritical steam cycle can be relatively straightforward (Bruce and others, 2018).

Amine-based post-combustion capture is frequently assumed to capture 90% of the CO₂ in power plant flue gases, and this is the design performance adopted by both the Boundary Dam 3 and Petra Nova facilities. However, the process is not fundamentally limited to this level, and can be used to capture up to 99% of the CO₂ present in coal plant flue gases with only marginal increases in the cost of the process (IEAGHG, 2019, 2020a; Jiang and others, 2020). Although some cost analyses have considered such ‘high capture rate’ cases, most analyses performed to date (and those considered in this review) adopt the 90% convention. It should be noted that the presence of these uncaptured emissions puts such plants at a particular disadvantage in net zero scenarios, in which the released CO₂ must be offset by negative emissions elsewhere (see Section 4.3).

This report also considers CO₂ capture from combined cycle gas turbines (CCGT), as this case is frequently included alongside coal power cost estimates in CCS cost studies. As for coal-fired power plant, post-combustion capture with amine-based solvents has become the leading technology for near-term plans for deploying CCS on new or existing CCGT plant. However, due to significant differences in flue gas composition, the process design and solvent formulation will differ for natural gas-based facilities (Soltani and others, 2017). In particular, CCGT flue gas contains much lower CO₂ concentrations (around 5% relative to 10–15% for coal flue gas), higher oxygen concentrations (which can be detrimental for solvent performance), but lower concentrations of other contaminants such as SO_x and particulates.

The focus of this review is on the costs of pulverised coal-fired power plants equipped with amine-solvent-based capture, which will be abbreviated as coal-CCS. For generic ‘new plant’ cases, the power plant itself is usually assumed to be a high-efficiency supercritical or ultrasupercritical (USC) plant using state-of-the-art steam conditions, while retrofit costing may consider older plant designs. Cases examining the cost of CCGT with CCS usually consider new, high-efficiency turbine designs, and will be abbreviated to CCGT-CCS where necessary (note that, where used by the original source, the alternative abbreviation of NGCC (natural gas combined cycle) is replaced).

2.3 OTHER CAPTURE TECHNOLOGIES

Various technology options exist for post-combustion capture which could provide alternatives to the solvent-based processes described above, including processes based on solid sorbents and membrane separation (Lockwood, 2016). Both alternatives offer potential advantages over solvent-based systems, particularly with respect to much lower water consumption, while membrane-based systems do not require steam extraction from the plant (instead using electrical power for vacuum pumping). However, these technologies have yet to be demonstrated at full scale for a power plant, with both sorbent and membrane systems currently trialled at scales of around 10 MW equivalent. Cost estimates for full-scale application of these technologies therefore tend to be highly uncertain and are primarily aimed at selecting the most suitable technologies for research funding.

Pre-combustion capture is heavily associated with integrated gasification combined cycle (IGCC) power plants, in which coal is gasified to form syngas (a mix of hydrogen and carbon monoxide (CO)) which fires a combined cycle gas turbine, similar to those used for power generation from natural gas (Sloss, 2019). In the pre-combustion capture format, the CO is converted to CO₂ via a water gas shift reaction and separated from the gas stream using CO₂ binding solvents. Starting in the 1990s, IGCC technology without CO₂ capture has been demonstrated at only a few plants globally, including the 540 MW Nakoso plant completed in Japan in 2021. Full-scale implementation of the pre-combustion capture concept has seen high-profile setbacks, most notably at the abandoned Kemper project in the USA and China's stalled GreenGen project (Lockwood, 2021b). This technology therefore features in relatively few recent CCS cost studies.

Some of the most promising emerging technologies for CCS on power plants involve directly incorporating the capture process with the power generation plant. One such example is a form of oxyfuel combustion process known as the Allam-Fetvedt Cycle which uses the CO₂ generated by a high-pressure, oxygen-fired combustion to drive a highly efficient power cycle (Brayton Cycle) with CO₂ as the working fluid (Zhu, 2017). This relies on gaseous fuel and has so far only been demonstrated on natural gas, although a similar concept using coal-derived syngas is currently being tested by technology developers 8 Rivers Capital for Low Emission Technology Australia (LETA, 2020). The natural gas-fired format has been demonstrated at 50 MWth scale in Texas and commercial-scale plants are currently planned in the USA, the UK, and Canada (Patel, 2021; Shaw, 2021; Kanata, 2021).

Another competitive concept employs a molten carbonate fuel cell as a unit to process power plant flue gas to pure CO₂. Introduced to the fuel cell cathode, the CO₂ component of the flue gas is oxidised and passed through the electrolyte barrier as carbonate ions, before being reduced back to CO₂ on the anode side (Lockwood, 2016). The device is separately fuelled by natural gas which is internally reformed to hydrogen, and the fuel cell generates an additional supply of electricity. Both the Allam-Fetvedt Cycle and molten carbonate fuel cell concepts feature in some cost analyses as they are

seen as representing a current benchmark for potential technology-based cost reductions (Wood, 2018; IEAGHG, 2020a).

2.4 TRANSPORT AND STORAGE OF CO₂

Nearly all commercially operating CCS facilities transport CO₂ in a high-pressure, supercritical state through pipelines to suitable geological storage sites (where the facility is already suitably located above a storage site, transportation may not be necessary). CO₂ transport by pipeline is a well-established technology, as over 7000 km of pipeline network has been deployed in the USA to support the use of CO₂ in EOR (IEA, 2020b). CO₂ storage sites generally require the presence of layers of porous rock found in sedimentary basis, which includes deep saline aquifers and depleted oil and gas reservoirs. A ‘cap rock’ of less permeable material must be located above the porous layer to prevent upwards migration of the CO₂. Supercritical CO₂ is injected into these deep formations through injection wells, which are usually accompanied by other wells used for monitoring of the site. Storage sites can be located onshore or offshore and, while offshore storage presents greater costs, it has become the dominant near-term focus for emitters in Northern Europe.

There is growing interest in the use of ships for transportation of CO₂, typified by Norway’s Northern Lights project, which aims to collect CO₂ by ship from various locations in Northern Europe (Equinor, 2020). In this case, ships will deliver CO₂ to an onshore collection point, where it is transported to an offshore storage site via an undersea pipeline.

However, the vast majority of CCS cost studies have assumed CO₂ transport by pipeline, with the choice of onshore or offshore storage dependent on the location of the study. Frequently, a general figure of around 10–20 \$/t is applied to cover all transport and storage costs, although more site-specific cost studies may base these costs on pipeline length and even the geological characteristics of the storage site (such as permeability of the rock).

An alternative option is to convert captured CO₂ into useful products, such as concrete, polymers, or fuels (Zhu, 2018). This approach is known as CO₂ utilisation and gives rise to the now widely used combined abbreviation ‘CCUS’ (carbon capture utilisation and storage). However, given that CO₂ utilisation is rarely considered by benchmark cost analyses for CO₂ capture, the term CCS is used throughout this report.

2.5 SUMMARY

- Significant global interest in CCS as a climate change mitigation technology arose in the late 1990s, with recently renewed interest in some regions associated with more ambitious climate policy goals;
- While much current policy interest in CCS is focused on non-power applications, power sector CCS projects are still planned in several countries, including the USA (coal and gas), UK (gas and biomass), and China (coal);

- The two existing coal power plant applications of CCUS and the majority of planned projects are based on post-combustion capture technology using amine-based solvents – this technology forms the basis of most CCS cost assessments;
- Post-combustion capture technology can be applied to new plant or retrofitted to existing power plants, with different technical and cost implications;
- Other, less-established capture technologies with potentially highly competitive costs include the Allam-Fetvedt Cycle technology and fuel cell-based concepts;
- Pipeline transportation and geological storage of CO₂ are well established technologies, with costs dependent on a number of factors including pipeline length and geological suitability.

3 APPROACHES TO CCS COST ANALYSIS

There are many approaches available for assessing the cost of emerging technologies such as CCS, and the most appropriate method for a given cost comparison exercise will depend heavily on the primary objective of the analysis and its intended audience. Rubin and others (2015) distinguish between two main purposes for cost estimates: technology assessments, such as those used in the selection of different capture technologies; and policy assessments, which are intended to support regulatory, legislative, and advocacy activities. Cost estimates may also focus on a specific plant or project, or aim to provide a generic cost for a typical plant of a stated size. In the latter case, the general region in which the plant is to be located (for example, North-Western Europe) is usually also specified. Unlike most other forms of low-carbon power generation, CCS costs must also distinguish between retrofit costs and the cost of a new power plant. Retrofit cost analyses are often, but not always, calculated on a plant-specific basis, while new plant costs are usually calculated for a generic, large capacity (600–1000 MW) plant using state-of-the-art technology.

Most costing methods fundamentally adopt a ‘bottom up’ approach, in which the capital costs of all plant components are estimated, using sources such as vendor data or other published literature (Rubin, 2019). These costs are summed and combined with estimates for construction and engineering costs, as well as any other project costs that might be incurred in the building of a complex plant, such as permitting, insurance, and land costs. Annual costs for plant operation and maintenance, as well as fuel costs, are also estimated and combined with capital costs to obtain total lifetime outgoings for the project.

In order to assess the actual cost performance of the plant, these total costs must then be expressed in terms of a unit of production. For power plants, the cost of producing each unit of electricity (\$/MWh) is the obvious choice, and should give an indication of the average electricity price the plant requires to be profitable. Another popular means of assessing the economic performance of CCS and other low-carbon technologies is to present costs on a basis of CO₂ captured or mitigated (\$/tCO₂). The best approach will depend on the objective of the analysis. While an investor may wish to determine the price at which CO₂ must be sold to make a profit, a government or regulator may look to determine the value of a carbon tax which would incentivise the installation of CCS.

3.1 LEVELISED COST OF ELECTRICITY

First developed in the 1970s, the levelised cost of electricity (LCOE) has become the dominant standard for comparing the cost of various forms of power generation, and is widely used by investors in new power projects, for assessment of new technologies, and to inform public and policy debate around the cost of energy. LCOE is based on a sum of all power plant costs, including capital and operational costs, over its operational lifetime, with each year’s costs adjusted by a discount rate (r). This ‘levelising’ – a standard practice in financial analysis - reflects the time-dependent value of money,

in that a future expense has less value than an outgoing today. The discount rate typically takes the value of the current interest rate or the weighted average cost of capital (WACC) for the investing company (a combination of interest rates and return on equity requirements). To obtain the LCOE, the levelised total lifetime cost is then divided by the lifetime energy output of the plant, which is also discounted in each year in the same manner as the costs:

$$LCOE = \frac{\sum_{t=1}^T \frac{\text{Capital costs in year } t + \text{Operating costs in year } t}{(1+r)^t}}{\sum_{t=1}^T \frac{\text{Energy generated in year } t}{(1+r)^t}}$$

where t is the year in which costs are incurred, T is the plant's economic lifetime in years, and r is the discount rate. A number of influential assumptions are included in the calculation of LCOE, including future fuel costs, interest rates, and the capacity factor of the plant. Owing to the relative simplicity of the calculation and apparent ease of comparison between technologies, LCOE remains a highly popular metric. It essentially represents the average revenue the plant would need for each unit of electricity sold in order to cover all of its lifetime costs, assuming no other income is generated.

However, the growing adoption of VRE, particularly in the form of wind and solar power, has severely reduced the utility of LCOE for power system planning in recent years. These energy sources lack various qualities which have previously been assumed to be inherent to conventional power plant, or already adequately provided by the existing grid, including the ability to deliver generation when required (often termed 'dispatchable capacity'), and the provision of grid balancing services such as inertia, frequency response, and reactive power (Heptonstall and others, 2017; Lockwood, 2020). As the proportion of VRE grows, reaching beyond 30% of total generation for several national or regional power grids, the need to ensure availability of these services has grown in importance, inducing many electricity system operators to introduce separate markets for reliable capacity or expand existing compensation for grid balancing services (Lockwood, 2020). As a consequence of this trend towards more complex grid operation, the limitations of LCOE in power system planning have also become more apparent.

A FUNDAMENTAL SHORTCOMING OF LCOE IS ITS
FAILURE TO CONSIDER THE TEMPORAL OR SPATIAL
VALUE OF ELECTRICITY SUPPLY – IT ASSUMES THAT ANY
AVAILABLE POWER CAN BE DELIVERED WHEN AND
WHERE IT IS REQUIRED.

3.2 ALTERNATIVES TO LCOE

As a result of these limitations, several alternatives to LCOE have been proposed in recent years, with the aim of better quantifying the overall contribution of an energy source to the operation of the electricity grid. These methods have been thoroughly summarised in recent reviews by Graham (2018), IEAGHG (2020b), and Byrom and others (2021). Alternative metrics nearly all take into account the characteristics of the system to which the new generating capacity is being added, in order to assess the value of a new unit of generation to those particular circumstances. This naturally adds a much greater level of complexity to the analysis, and usually requires some form of modelling of the existing energy system. However, this level of detail is ultimately necessary if the true value of capacity added to the grid is to be determined; the technology which provides the lowest cost decarbonisation at first may no longer be the lowest cost option at higher levels of deployment. Prominent examples of LCOE alternatives are briefly outlined here.

3.2.1 Levelised avoided cost of electricity (LACE)

Developed by the US-based Energy Information Administration (EIA), this metric quantifies the likely income generated by a given generating technology from energy markets and mechanisms to compensate available capacity (where applicable). This requires a model of the energy market and calculation of marginal generating costs and operating hours over representative time periods over the course of the year, for which the EIA uses the National Energy Modelling System (NEMS). Nine different time periods are analysed, capturing the seasonal characteristics of spring/autumn, summer and winter, and daily variation between daytime, night, and ‘shoulder’ (the transition between peak and off-peak daily demand). LACE can be used in combination with LCOE to estimate the potential profit to the generator, or in other words, how much the market currently values a given technology (Graham, 2018; EIA, 2020).

A high LACE indicates greater income potential, and a high LACE-to-LCOE ratio indicates a favourable investment. This method captures the value of flexibility, as technologies which are able to generate consistently through periods of high-value electricity (peak demand) will obtain a higher LACE than more intermittent generators, whose output may not match demand.

3.2.2 Value-adjusted levelised cost of electricity (VALCOE)

Value-adjusted levelised cost of electricity (VALCOE) was developed by the IEA for use in the annual World Energy Outlook, starting with the 2018 edition (IEA, 2018, 2020a). It uses an hourly electricity market model to add three adjustment factors to each technology’s LCOE: an energy value calculated from the system marginal price, a capacity factor, and a flexibility factor. The energy correction factor is usually the most significant, and it can be understood as a means of placing greater value on energy that is generated when demand is high. In order to derive a value for capacity, the VALCOE calculation models a capacity market even for regions where they do not actually exist, simulating a process of

bidding by dispatchable capacity to meet the system's peak demand. The flexibility correction refers to value from markets for ancillary services and grid reserve. The value provided by a technology in each of the three services is compared to average value provided by the whole electricity system (Figure 2). The difference between these two values then provides the 'correction factors' which are used to adjust each technology's LCOE. Essentially, each technology is credited for any value it provides in excess of the system average.

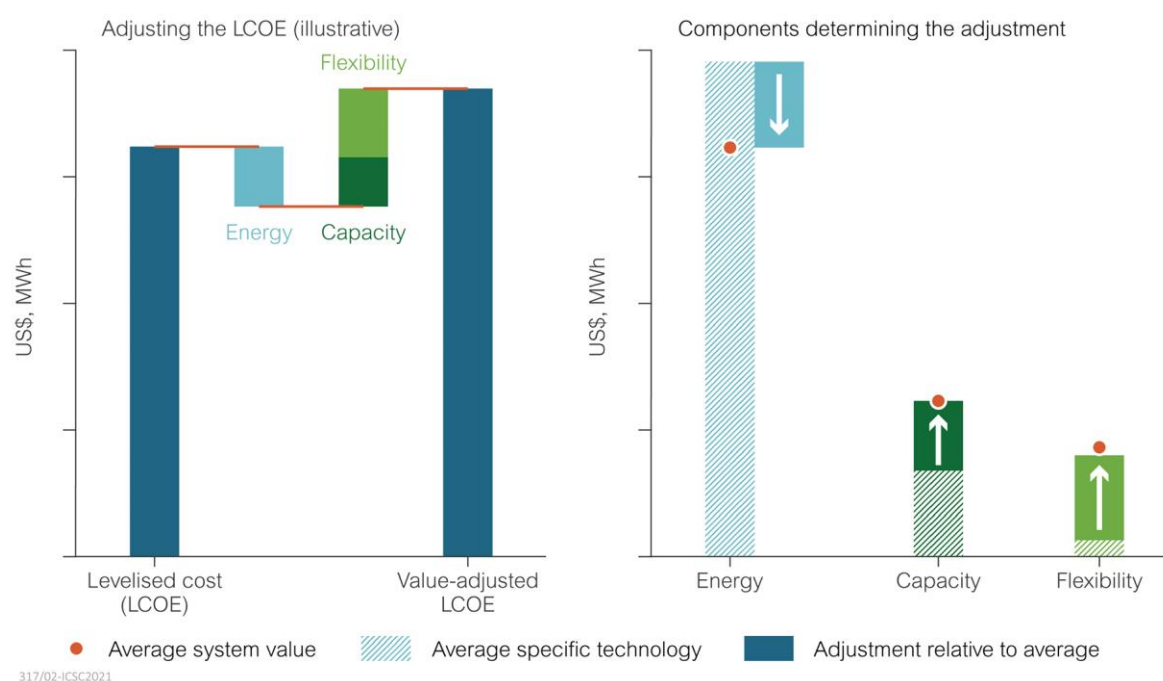


Figure 2 Example of the VALCOE calculation (IEA/NEA, 2020)

3.2.3 Integration costs

Several methods have sought to adjust a standard LCOE for VRE technologies with the addition of 'integration costs', which refer to a range of costs incurred by the rest of the electricity system to incorporate the new capacity (Heptonstall and others, 2017; Byrom and others, 2021). These can include the need for balancing generation, transmission infrastructure to deal with grid constraints, costs due to lower load factors for thermal plant, and curtailment of renewables. However, these methods are particularly vulnerable to the risk of double counting, as many grid modifications will benefit more than one technology, and conventional plant may also incur or benefit from some of the same integration costs. Known as 'System LCOE' (SLCOE), a method developed by Ueckerdt and others (2013) attempts to encompass all integration costs thoroughly by calculating the total cost of the system with and without the additional MWh of VRE generation (total system cost includes all the grid's capital and operating expenses and is discussed further in the following section).

$$SLCOE^S = LCOE^S + \frac{RSC - TSC_0}{EG} - TSC_0^S$$

Here, TSC_0 is the total system cost of a system prior to the addition of the new technology; TSC_0^S is the same cost expressed on a per MWh basis; RSC is the system cost of the residual system (not including costs associated with the newly deployed technology); and EG is the total energy generated by the new technology. The quantities added to the LCOE comprise the integration costs, capturing the extent to which the residual system costs have increased relative to their original costs, without the VRE generation – for example, due to greater procurement of balancing power, or installation of new peaking plant.

Enhanced levelised cost of electricity is another example of an LCOE adjusted with integration costs, and was developed for use by the UK government (BEIS, 2020). The cost of the ‘system impact’ of each technology is calculated based on its effect on the wholesale market, capacity market, balancing and ancillary service markets, and network costs over a specified time period. This cost is then converted to a £/MWh value by dividing by the total amount of electricity generated over this timeframe, as well as converting to present day cost using the same discounting of future costs used for LCOE. This analysis requires the government’s dispatch model to simulate the likely utilisation profile of a given energy mix, according to a range of scenarios with varying demand and cost projections. The system impact costs are then used to adjust the conventional LCOE.

3.2.4 Total system cost

A rigorous method of calculating the true cost of a generating technology is by quantifying its effect on all the costs incurred by the electricity grid, known as the ‘total system cost’ (see Figure 3). This value expresses the total cost of delivery of a fully functioning, reliable electricity grid, able to deliver electricity when and where it is required across a representative range of weather and demand scenarios. This system cost can be regarded as most closely approximating the overall cost of grid decarbonisation which will be incurred by consumers or taxpayers, and can therefore be of greater use to policy makers and system planners than energy-focused metrics such as LCOE. Calculating and comparing the total system cost for different scenarios requires a complex model of the energy system being studied. This is usually based on the combination of a dispatch or ‘unit commitment’ model, to simulate the behaviour of generators throughout the day, and a ‘generation expansion planning’ model, which (over longer time periods) deploys new generating capacity and retires old capacity to meet growing electricity demand and carbon targets. To reduce computation time, these models generally make several simplifying assumptions, but can typically simulate dispatch at a temporal resolution on the order of one-hour steps. The deployment model seeks to minimise the total system cost function, which is a sum of all fuel costs, operating costs, and capital costs, all while observing system balancing constraints such as grid reliability standards and the need for inertia and fast-response reserves. This optimisation is repeated for the electricity demand and carbon requirements projected for selected future years, usually chosen at five or ten-year intervals.

A number of models capable of this kind of analysis have been developed, many of which are reviewed by Graham (2018) and Heuberger and others (2017). Some notable differences between how models approach the problem include the level of temporal resolution, the selection of representative weather data, treatment of transmission constraints (often absent), whether time periods are solved simultaneously or sequentially, and the treatment of energy storage behaviour.

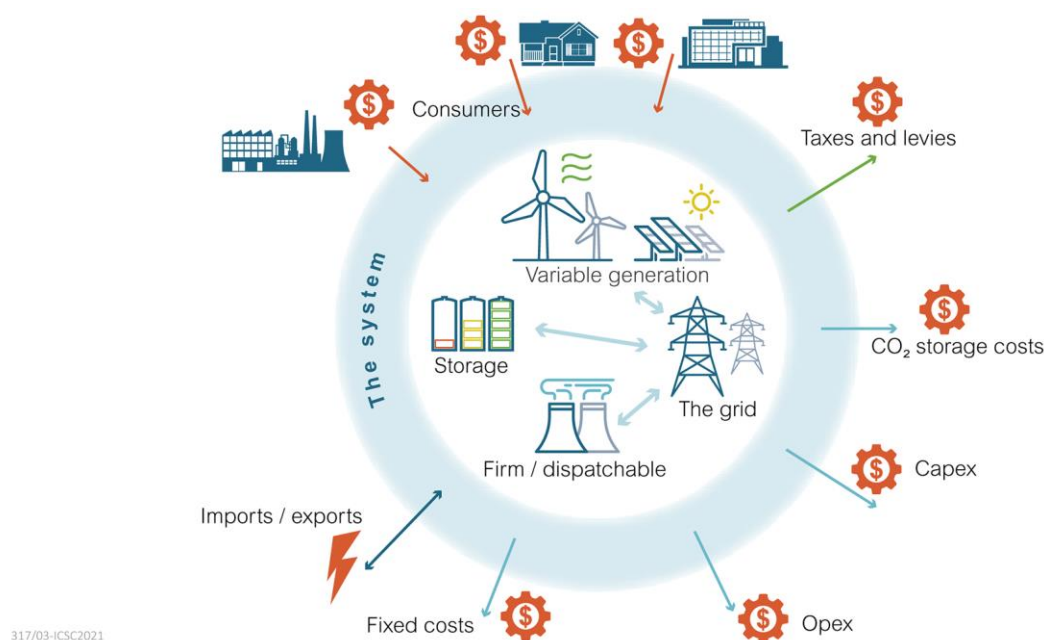


Figure 3 The boundaries of the electricity 'system' considered by total system cost analysis, showing the cash flows in and out of the system (Byrom and others, 2021)

The importance of any given technology in minimising total system cost can be quantified by forcing the model to reach decarbonisation targets (such as net zero) by deploying a restricted range of technologies. For example, the total cost of reaching net zero with and without CCS can be compared (see Section 4.3). However, the drawbacks of such analysis include the need for a complex model and skilled operators, and, unlike LCOE and its derivatives, it does not provide a convenient set of values for directly comparing different generating technologies. Some attempts have therefore been made to express total system costs in the form of a \$/MWh value.

System Cost of Replacement Energy (SCoRE)

Developed by Gamma Energy and Red Vector, SCoRE is one such technology-focused metric derived from total system cost (Gamma Energy Technology, 2019). Aiming to reflect the process undertaken by many established grids as they attempt to decarbonise, SCoRE compares the system cost effect of replacing existing capacity with alternative low-carbon sources. An existing technology to retire, such as coal or gas power, is selected for use as a consistent reference across the analysis. The difference in total system cost before (TSC_0) and after (TSC_a) replacement with a new unit of generating capacity (a) is calculated, and then divided by the total energy generated by the new capacity (EG_a) to obtain a \$/MWh value:

$$SCoRE_a = \frac{TSC_a - TSC_0}{EG_a}$$

This metric therefore includes the cost of construction, operation and integration of the new technology, while crediting the new plant with any reduced costs associated with the closure of existing capacity. The SCoRE for each technology will vary according to how much of that generation source is already deployed on the grid, allowing it to be used to determine the deployment levels at which an alternative option may become more competitive. A SCoRE can also be calculated for a mix of technologies being added to the grid, and by extension, an optimum mix can be determined from the lowest cost SCoRE (see Section 4.3).

3.3 COST OF CO₂

The other fundamental basis for representing the cost of CCS is using a cost per tonne of CO₂, which can be expressed either as a cost per tonne ‘captured’ or ‘avoided’. Both these costs are usually based on the same sum of the levelised costs (capital and operating costs) used by the LCOE plant, but divided by the total CO₂ produced over the lifetime of the plant rather than electricity generation. In fact, they are frequently calculated using the LCOE itself, by also factoring in the CO₂ intensity of the electricity generated. However, the cost of CO₂ captured is most simply expressed as:

$$\text{Cost of CO}_2 \text{ captured} = \frac{\sum \text{capital costs} + \text{O\&M costs} + \text{fuel costs}}{\text{CO}_2 \text{ captured}}$$

The cost of CO₂ avoided compares the emissions produced by the CCS-equipped plant with a reference plant without CCS, which produces the same amount of electricity:

$$\text{Cost of CO}_2 \text{ avoided} = \frac{\text{Cost of plant with CCS} - \text{Cost of plant without CCS}}{\text{CO}_2 \text{ emissions without CCS} - \text{CO}_2 \text{ emissions with CCS}}$$

The cost of CO₂ avoided accounts for the fact that CCS imposes an energy penalty on the power plant and therefore produces more CO₂ for each unit of electricity generated. In order to produce the same net output of electricity, the plant must capture not only the CO₂ emissions of the reference plant but the additional emissions associated with this energy penalty. Consequently, the cost of CO₂ avoided is generally greater than the cost of CO₂ captured.

The cost of CO₂ captured is most often used for comparison of different capture technologies or for tracking cost reduction progress for a given capture technology. For this reason, it often omits the cost of CO₂ transport and storage, and sometimes even the cost of CO₂ compression (typically around 5–10 \$/t). For retrofit applications where the capture plant may be considered as a stand-alone operation, costs associated with the power plant itself may also be excluded. Conversely, the cost of CO₂ avoided should always cover all costs associated with mitigating CO₂ emissions, including CO₂ transport and storage.

The cost of CO₂ captured can be directly associated with the price at which a plant would need to receive revenue from the CO₂ it produces, and indeed, some recent publications have referred to it simply as the ‘breakeven CO₂ sales price’ (NETL, 2019). Conversely, the cost of CO₂ avoided can be associated with the CO₂ emissions price (such as a carbon tax) which would need to be imposed to make the CCS-equipped plant more economically viable than the unabated plant.

A key challenge in making meaningful comparisons with the cost of CO₂ avoided is the choice of reference plant, which could, in the case of power generation, be an unabated coal- or gas-fired plant. This choice may depend on the context of the grid in question. While a coal-fired reference plant is normally chosen for assessment of coal-CCS options, a gas plant may make more sense if a realistic alternative for system planners is the replacement of the unabated coal plant with a new gas plant.

A third way of expressing costs in terms of tonnes of CO₂ is the ‘cost of CO₂ abated’, which can also be referred to as the cost of CO₂ mitigated or reduced. Unlike the first two metrics, which are generally only applied to CCS costing, the cost of CO₂ abated is more widely used for assessing carbon emission reduction technologies or different emissions trajectories for a whole system. According to Rubin (2012), this value differs from CO₂ avoided in that the reduced emissions case does not necessarily have to produce the same quantity of product (for example, electricity) as the reference scenario. However, this constraint is adhered to in most analyses (*see* Section 4.2.3). In practice, for CCS technologies, CO₂ avoided is frequently equivalent to the concept of CO₂ abated.

3.4 CONSISTENCY IN COST ANALYSIS

Obtaining useful and comparable cost estimates for emerging technologies such as CCS can be highly challenging, and there is a need for consistency across all aspects of the calculation, including the assumptions and methodology employed. It has long been recognised that there are significant differences between the approaches used by various authors and organisations, leading to results that are not directly comparable (Rubin and others, 2015; Rubin, 2019).

Some principal points of variation between different cost studies include:

- Items included in capital costs, particularly those known as ‘owners’ costs’, including feasibility studies, permitting, and land purchase (often a set percentage of total capital costs);
- Treatment of financing costs, including choice of discount rates, amortisation period, and allocation of interest accrued over the construction period;
- Contingency costs (usually divided into process and project contingencies and estimated as a percentage of total capital costs);
- Calculation method for CO₂ transport and storage costs (a flat rate per tonne may be used, or a calculation based on pipeline length and geological parameters);

- Inadequate adjustment of costs for location (USA or EU plant estimates may be simply transposed to other locations without accounting for variations in factors like project risk, labour or material costs);
- Inadequate adjustment of costs for time (cost inputs from older studies need to be updated for inflation and real changes in material and labour costs);
- Choice of plant capacity factor (baseload factors of 85–90% are usually assumed, but this may not accurately represent the current or future status of coal and gas on the grid);
- Inclusion of a carbon price or other incentives; and
- Choice of unabated reference plant for avoided cost of CO₂.

Variation in overall capital cost estimates can be particularly significant, owing not so much to underlying equipment and construction costs, but to the selection of cost adders to represent other miscellaneous project costs (often termed owner's costs) and project and process contingencies which reflect the level of uncertainty and risk of cost escalation. These are usually applied as percentages of the basic construction cost and should reflect local factors and the level of maturity of the technology. The choice of contingency factors and other capital cost adders for a given plant is often linked to the stipulation of 'first of a kind' (FOAK) or 'nth of a kind' (NOAK) status, with the latter term denoting a plant which has become commercially established and technically standardised. The risks and cost uncertainties inherent to a FOAK technology demonstration plant are typically expressed by imposing higher contingencies and higher interest rates. However, Rubin (2019) and IEAGHG (2021) assert that attempts to estimate NOAK costs for technologies still at the FOAK stage (such as CCS) should not be made using the conventional 'bottom up' cost method, instead proposing a hybrid method in which typical technology 'learning rates' are applied to FOAK estimates.

The choice of contingency factors and discount rates for the LCOE calculation are more influential for high capital-cost technologies (such as coal and nuclear plants) and discount rates in particular can have an important effect on the final costs of such plants (IEA/NEA, 2020). Given the uncertainty over the interest rates which might be secured for a project using relatively new technology, some studies provide cost estimates at two or three different discount rates in order to express the potential for cost reductions under favourable financing terms. Higher discount rates may reflect a higher proportion of equity expected in project financing, which is typical of riskier technologies and requires higher rates of return.

Rubin (2012) found that inconsistencies in these parameters could lead to significant differences of 20% or more in reporting the cost of otherwise identical carbon capture systems. In response to this issue, efforts have been made to converge on a more universal standard of cost analysis for CCUS systems, typified by the White Papers *Toward a common method of cost estimation for CO₂ capture and storage at fossil fuel power plants* (Rubin and others, 2013) and *Towards improved guidelines for cost evaluation of carbon capture and storage* (IEAGHG, 2021). Large research organisations and government departments have also used their resources to establish an internal uniform cost analysis

basis. Most notably, the United States Department of Energy's (USDOE) National Energy Technology Laboratory (NETL) has produced thorough and regularly updated 'baseline' cost estimates for fossil fuel generation technologies since 2010, with and without CCUS technology, which have seen international adoption and imitation (NETL, 2019; Singh and others, 2019). The parameters and assumptions used (including plant size, location and financing cost) in these baseline cases are also used for consistent economic assessment of new capture technologies under USDOE funding programmes. Other organisations with standardised cost methodologies which have seen wider usage include the Wood Group (previously Amec Foster Wheeler), the Electric Power Research Institute (EPRI), the IEA Greenhouse Gas R&D Programme (IEAGHG), and the Global CCS Institute (GCCSI).

Rubin (2012) identifies a hierarchy of cost estimation methods according to the level of detail and uncertainty in the analysis. Starting with the most uncertain, these are:

- Expert elicitations;
- Using published values;
- Modifying published values;
- Deriving new results from a model; and
- Commissioning a detailed engineering study.

As the more uncertain methods ultimately rely on data from the more detailed modelling or engineering studies, these more rigorous approaches are of particular interest and form the basis of this cost review. While results from detailed engineering studies performed for specific projects are not usually publicly available, engineering firms are sometimes commissioned to carry out generic analysis for publication, using in-house data, costs from vendors, and potentially experience from work on similar projects. Equipment costs can be obtained from vendors or engineering companies and scaled according to the stipulated plant size. For established, commercially sold components, these estimates will be based on actual prices, but for new technologies and components, or ones yet to be used at the required scale, estimates may be based on appropriately adjusted costs for similar equipment.

These varying levels of certainty are often quantified according to standards set by organisations such as EPRI or the American Association of Cost Engineering (AACE). For example, an AACE Class 4 estimate is considered appropriate for a proposed project which has completed a feasibility study and has a certainty range of -15%/+30%. Higher levels of accuracy are usually associated with actual projects which have moved to more advanced stages of development, such as front end engineering design (FEED) studies.

Estimation of CCS costs for retrofit projects brings a specific set of problems and choices about assumptions. In particular, the capital cost of the existing power plant can be treated as a 'sunk cost' (essentially disregarded) or included in the estimate according to the extent to which it has already been amortised (*see* Section 4.1.2). A range of local plant factors should also be considered, such as

available space, the presence of existing flue gas treatment equipment, and the ease of steam extraction from the existing steam cycle. While most retrofit cost studies examine a specific real plant case, some generic retrofit cost guidelines have been published (IEAGHG, 2011; NETL, 2016). A large group of power plants may also be assessed for retrofit costs using a few key parameters, such as plant efficiency and distance from CO₂ storage sites (IEA, 2016b; Singh and others, 2019).

It is therefore essential to consider the impact of varying assumptions when comparing cost results from different sources. By collating several leading cost estimates in the following chapter, this report does not intend for direct comparisons to be made between the presented results, but to provide an overview of the range of outputs which have been derived using various assumptions.

3.5 SUMMARY

- Levelised cost of electricity is a popular metric for comparing the cost of different electricity generating technologies, due to the relative simplicity of its calculation and ease of use;
- However, LCOE only values the generation of electricity and fails to account for other grid costs which are particularly associated with greater deployment of VRE;
- Alternatives to LCOE have been developed which consider the context of the grid's current energy mix;
- Total system cost is complex to derive, but provides the most thorough indication of the cost to society incurred by different electricity grid decarbonisation options;
- Carbon abatement technologies such as CCS can also be assessed in terms of the CO₂ they capture or avoid; and
- Energy system cost studies – particularly for emerging technologies – are notoriously sensitive to the choice of assumptions made and should be used (and compared) with caution.

4 COST COMPARISON OF LOW-CARBON POWER GENERATION TECHNOLOGIES

This chapter reviews a selection of the most recent and detailed cost assessments which have been published on CCS in the power sector, including standard LCOE analysis and some of the more complex, system-based metrics introduced in Chapter 3. Most of these studies fall within the more rigorous categories of costing methods outlined in Section 3.4, based on original plant cost models (Rubin, 2012). Cost studies which have compared CCS costs with other low-carbon power generation technologies are highlighted in Sections 4.1.3 and 4.2.3.

4.1 LCOE AND RELATED METRICS

4.1.1 International comparisons of CCS LCOE

A large number of published studies have derived LCOEs for various types of CCS power plant, using different capture technologies and locations, and widely varying assumptions. Some of the most informative LCOE calculations available include thorough studies of generic power plant cases, carried out by governments or international organisations with direct input from capture technology providers, usually for new-build power plants and using commercial or near-commercial technologies. Other informative analyses can be obtained from the detailed engineering studies conducted for planned CCS projects; these also tend to use well-established capture technologies, but are usually retrofit projects and therefore highly project specific.

A key reference for CCS costs in the power sector is the 2014 study completed by Amec Foster Wheeler (now part of the Wood Group) for IEAGHG, which undertook a detailed costing of new CCGT (1200 MW) and USC coal (1000 MW) power plants equipped with Shell Cansolv post-combustion capture technology (IEAGHG, 2014). This initial study took Northern Europe (Netherlands) as the location, but a 2018 report (also by Wood for IEAGHG) updated the analysis and translated costs to a range of other locations around the world, using local fuel prices and conversion factors for material costs, labour costs and productivity, as well as location-specific contingencies (Figure 4) (IEAGHG, 2018). No carbon price is considered, and CO₂ transport and storage costs are set at 10 €/t for all cases. The pulverised coal plants have a capacity factor of 90%, while CCGT cases are set at 93% (see Table 1 on page 44 for a more extensive list of parameters).

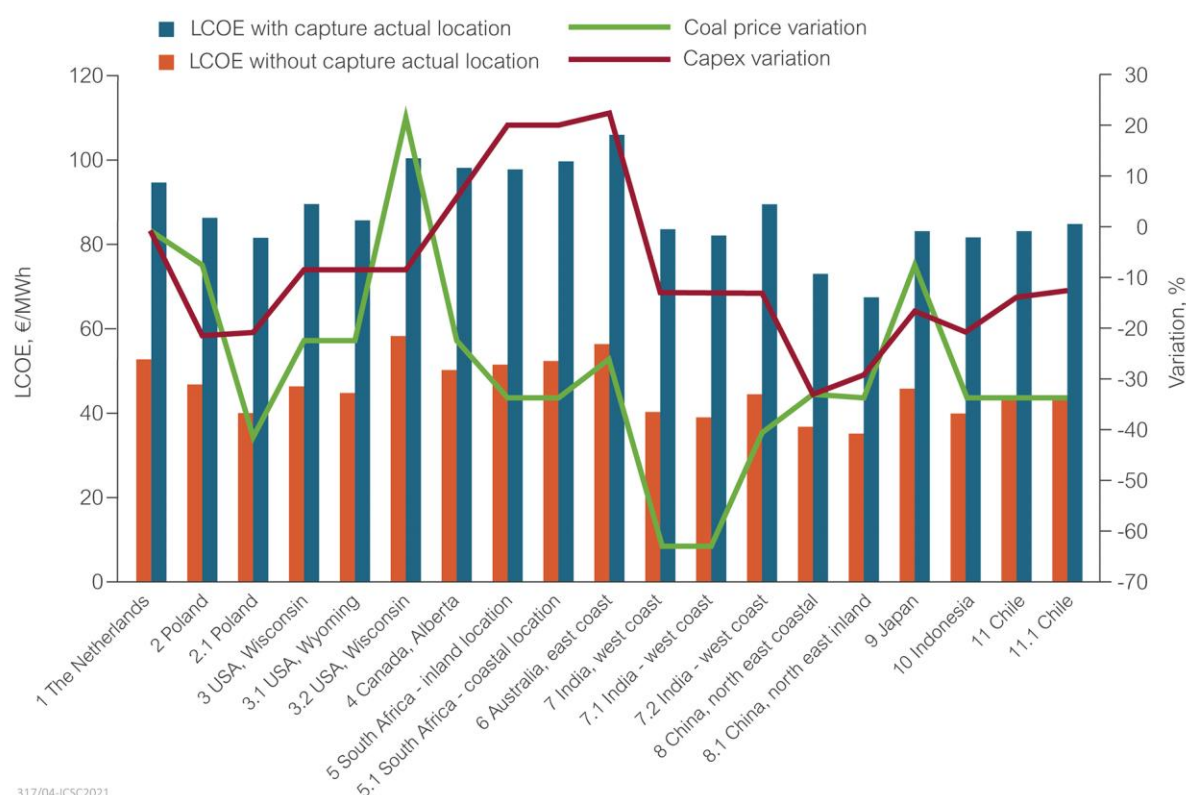


Figure 4 LCOE of supercritical coal plant at different locations, with and without CCS (IEAGHG, 2018)

The resulting LCOEs for CCS-equipped plant ranged from 68 €/MWh (80 \$/MWh) for an inland location in China, to 106 €/MWh (125 \$/MWh) for a location on the east coast of Australia. This variation can be attributed in large part to the difference in capital cost between the two locations, which is associated with much lower labour and material costs in China. Across all cases, there is an average increase of 94% in LCOE when going from the unabated plant to the CCS case, although this relative increase is as low as 74% for the Wisconsin location using a more expensive coal source (one of the highest absolute cost cases).

By comparison, the LCOEs for natural gas-fired cases with CCS range from 50 €/MWh (59 \$/MWh) in coastal India to 93 €/MWh in coastal South Africa (109 \$/MWh), and show a smaller average increase of 51% between the unabated and CCS cases.

In 2020, IEAGHG published an update of this cost study, considering the Netherlands reference location only (IEAGHG, 2020a). In addition to updating equipment and fuel costs and presenting results in 2018 euros (updated from 2016), this newer study uses a slightly larger (1500 MW) and more efficient combined cycle design. However, with no significant technological progress in either coal plant or solvent-based CO₂ capture technology to consider, LCOE figures remain only 1–2% higher than the 2018 report, at 53.3 €/MWh for unabated coal and 97.3 €/MWh for coal-CCS. For natural gas-fired plant, the higher efficiency and economies of scale afforded by the larger plant design were generally countered by increases in maintenance and natural gas costs, leading to a 1–3% increase

in LCOE for CCGT-CCS cases. More significantly, this study also considers cases which capture a higher proportion of CO₂ from the flue gas, taking 99% capture from coal and 98.5% capture as optimal points above which further increases are too costly. These ‘high capture rate’ cases are achieved with only modest increases in LCOE compared with the 90% case, of 4.3% and 5% for coal and gas respectively.

In 2018, Wood conducted a similarly detailed cost analysis of various CCS-based power generation options for the UK Government, reusing some of the analysis from the IEAGHG study (Figure 5) (Wood, 2018). In addition to standard cases based on natural gas-fired CCGT (1200 MW) and supercritical pulverised coal plants (1000 MW) with post-combustion capture (Shell Cansolv), this study also looked at other types of CO₂ capture including pre-combustion capture and oxyfuel combustion, as well as all three technologies applied to power plants fired with biomass. The study also examined two of the most promising emerging capture technologies for natural gas-fired plant, namely, the Allam-Fetvedt Cycle (developed by NET Power) and a CCGT using a molten carbonate fuel cell as the CO₂ capture plant (as developed by FuelCell Energy). The CCGT cases are based on two gas turbines with a net (unabated) power output of 400 MW each and a steam turbine of similar size, which represent one of the largest and most efficient turbines available at the time. The pulverised coal cases are based on a standard 1000 MW USC unit, so all cases vary in their net power output. The analysis also includes a carbon price which increases over time from 21.6 £/t in 2017 to 223 £/t in 2050.

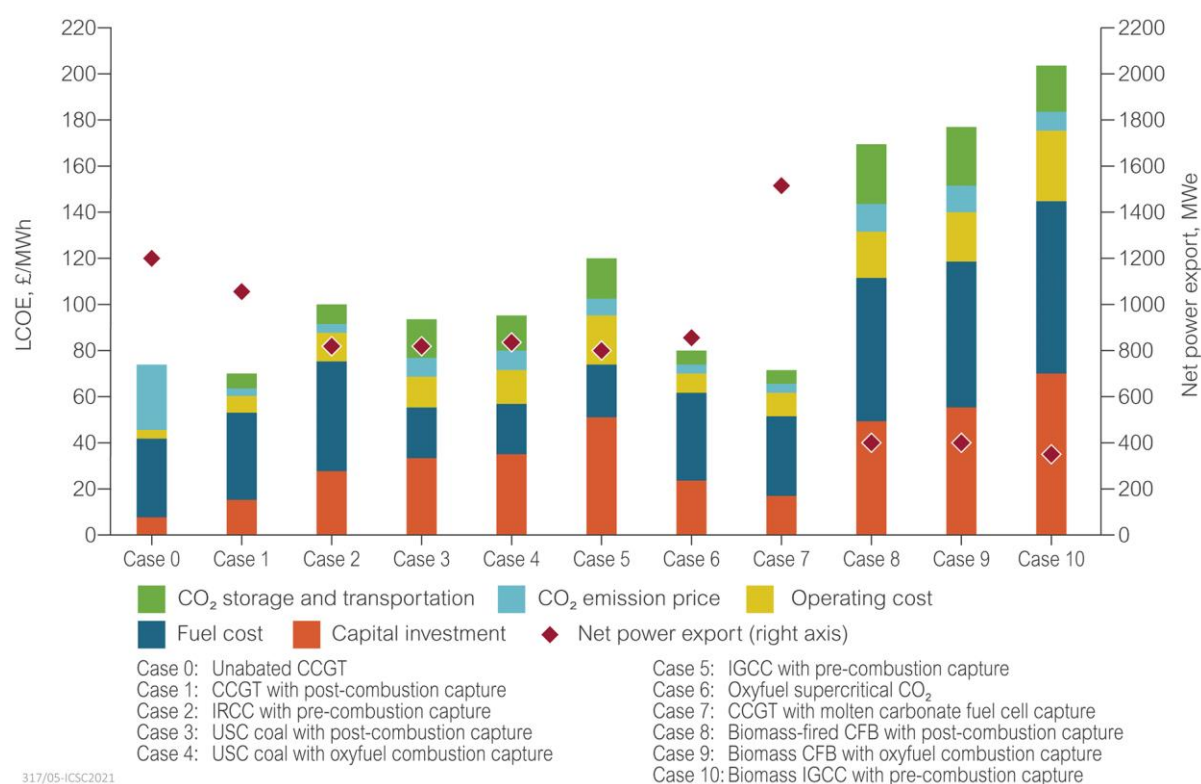


Figure 5 LCOE for various CCS power plant cases in the UK (Wood, 2018)

In this study, LCOEs range from 70.7 £/MWh (97.5 \$/MWh) for a CCGT with fuel cell capture to 204.3 £/MWh (281 \$/MWh) for a biomass-fired IGCC with pre-combustion capture. The lowest cost coal-fired case is a USC plant with post-combustion capture (93.3 £/MWh (128 \$/MWh)), but this is still significantly higher than CCGT with a similar post-combustion capture process, which comes in at 69.9 £/MWh (96.4 \$/MWh). Owing to the steady growth in carbon price assumed over the plant lifetime, this CCGT-CCS case is actually lower cost than the equivalent unabated case. There is no unabated coal case considered, but the lowest-cost coal-CCS plant represents a 26% increase in LCOE over the unabated gas-fired case.

In the UK context, the fuel cost advantage of a coal-fired plant compared to a gas-fired plant is outweighed by the much greater capital cost of a pulverised coal plant relative to a CCGT. This is due to generally high build costs in the country (including a high cost of labour), and the relatively small differential between coal and gas prices, with gas expected to see long-term low costs due to global shale gas production. Coal plant cases also emit more uncaptured CO₂ emissions, which incur additional costs, but LCOEs calculated without a carbon price still put the coal-based post-combustion cases at 28% more expensive than the equivalent gas-based case.

In the USA, NETL provides detailed costing of fossil-based power generation options, with and without CO₂ capture, in its ‘Baseline Studies for Fossil Energy Plants’, with a most recent update released in 2019 (NETL, 2019). The post-combustion cases again use Shell Cansolv technology, and all pulverised coal-based cases are standardised to produce the same net power output of 650 MW (increased from 550 MW in previous editions), so CCS-equipped cases have much larger gross capacities than unabated cases. Pre-combustion capture cases with IGCC power plants cover three different gasifier types (Shell, Chicago Bridge and Iron FSQ gasifiers, and General Electric) and have net power outputs from 499 MW to 641 MW.

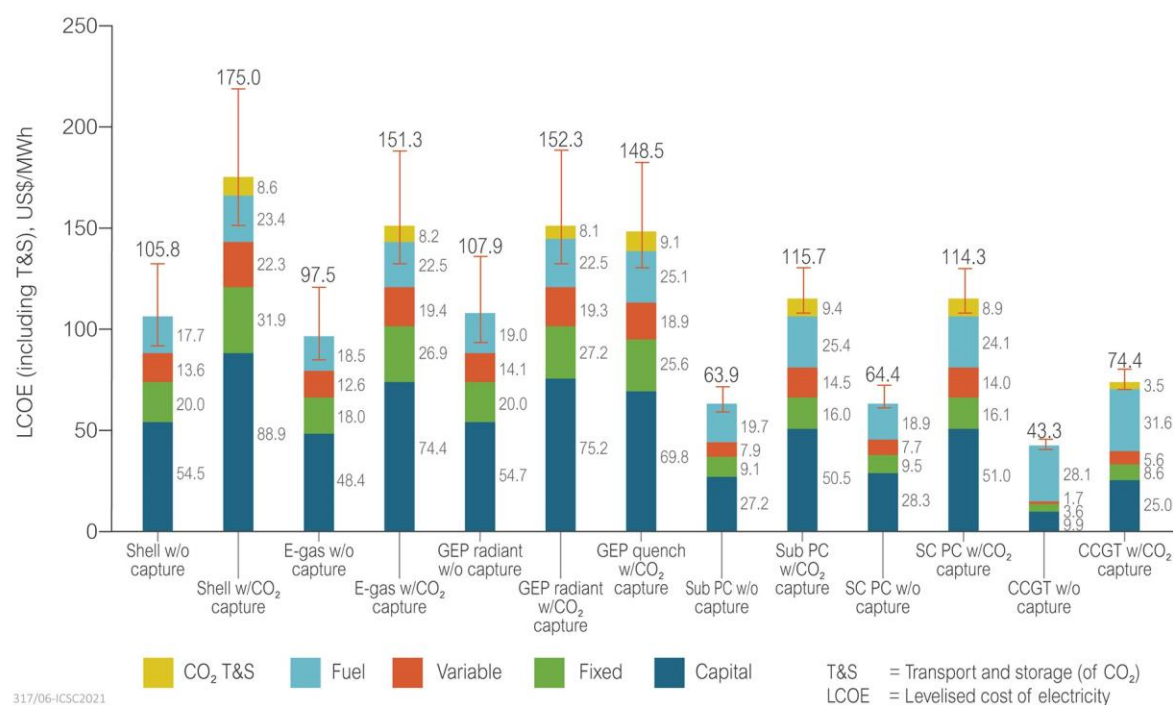


Figure 6 NETL baseline study results for coal- and gas-fired power plants with and without CCS (NETL, 2019)

This study derives an LCOE of 114 \$/MWh for a supercritical coal plant with CCS, representing a 77% cost increase over an unabated coal plant with equivalent power output, and a 53% increase over a CCGT plant with CCS (Figure 6). Around half of the contribution to LCOE for this case is from capital costs and, as for the UK study, the higher capital cost of pulverised coal plant significantly outweighs the lower fuel cost with respect to gas-fired plant. Indeed, this factor is even greater in the USA, due to much lower gas prices.

Lastly, a 2017 study by the Global CCS Institute (GCCSI) provided cost estimates for various kinds of coal and gas-fired CCS power plant in a selection of international locations (Figure 7). The costs are based on a methodology developed by Advisian/WorleyParsons, using real-world cost data obtained from CCS plant and similar infrastructure projects. As in the IEAGHG study discussed above, costs are first calculated for a reference location (USA) and then adjusted using local factors such as labour costs and fuel prices. In keeping with the NETL baseline studies, net power output is kept constant at 550 MW for nearly all cases examined.

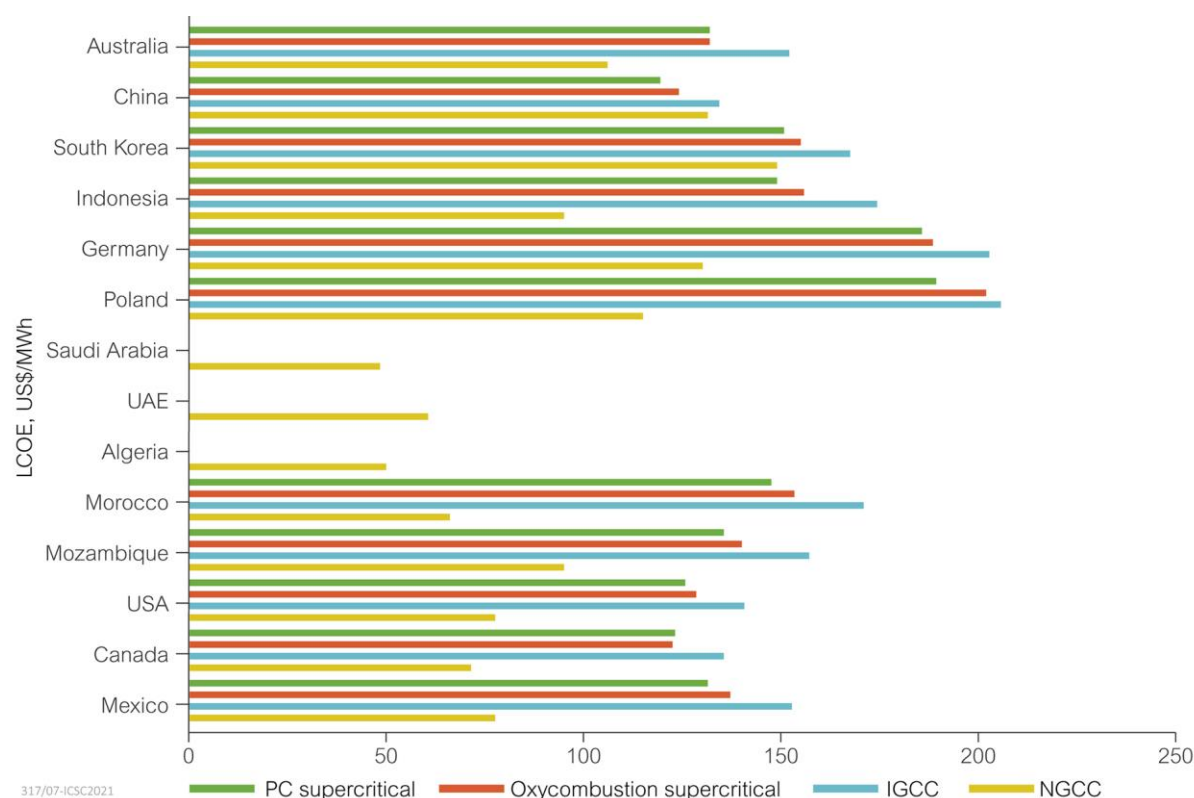


Figure 7 International comparison of CCS LCOE (Irlam, 2017)

This study finds costs similar to the NETL baseline studies for the US reference location, with an LCOE of 124–133 \$/MWh for a FOAK supercritical pulverised coal case; this represents a 69% increase over the equivalent unabated plant. CCGT plants with CCS are cheaper than pulverised coal with CCS in all countries studied other than China, although their costs are almost identical in South Korea. As found by the IEAGHG study, variation in LCOE between countries is largely due to variation in labour and equipment costs and fuel prices. Relatively low LCOE for coal-based cases are found in Canada and the USA, where low coal prices offset high labour and equipment costs, in China, where all three costs are relatively low, and Mexico, due to low labour costs. This study uses 2015 \$ and no carbon price.

4.1.2 LCOE estimates for retrofit cases

Assessment of LCOEs for retrofit CCS projects can be problematic, as there is no established approach for how the existing power plant costs should be treated. The capital costs of the power plant can either be fully included, treated as ‘sunk costs’ which are not included in the calculation, or included in project costs in proportion to the extent the plant has already been amortised. In addition, the remaining lifetime of the plant may be shorter than the economic lifetime assumed by standard LCOE analysis for a new plant (usually 25–30 years), or the retrofit may be accompanied by plant upgrading and lifetime extension.

The NETL fossil energy baseline costs (2015 edition) for a supercritical coal plant with CCS were converted to a Chinese retrofit context in a 2018 study by Singh and others (NETL, 2015; Singh and others, 2018). This study considers a larger, 2 x 600 MW unit plant with 20 years of remaining lifetime,

and includes power plant capital costs which have been depreciated over ten years of prior operation (other retrofit times are considered in a sensitivity analysis). Figure 8 shows the various factors that lead to an overall reduction in the cost of electricity from 133.2 \$/MWh in the USA to 94.3 \$/MWh in China. It should be noted that this earlier NETL publication uses the concept of ‘cost of electricity’ rather than a levelised cost, which calculates the ‘first year’ cost that would cover future year costs if escalated at the standard inflation rate (NETL, 2015). The authors also update the cost year of the NETL publication from 2011 to 2016 \$. As for the IEAGHG study previously discussed, the main cost saving in China is the much lower capital costs, but the Chinese plant suffers from a lower capacity factor (57%), due to current levels of overcapacity in the country. In Hao (2020), this cost of electricity is modified to cover retrofitted units operating at higher load (assuming priority dispatch) and with partial capture rates, in the context of determining the most economic pathway to achieving carbon intensity targets for the power sector. A first year COE of 553.5 CNY/MWh (81.3 \$/MWh (authors’ exchange rate)) is obtained for a plant with 90% capture operating at full load.

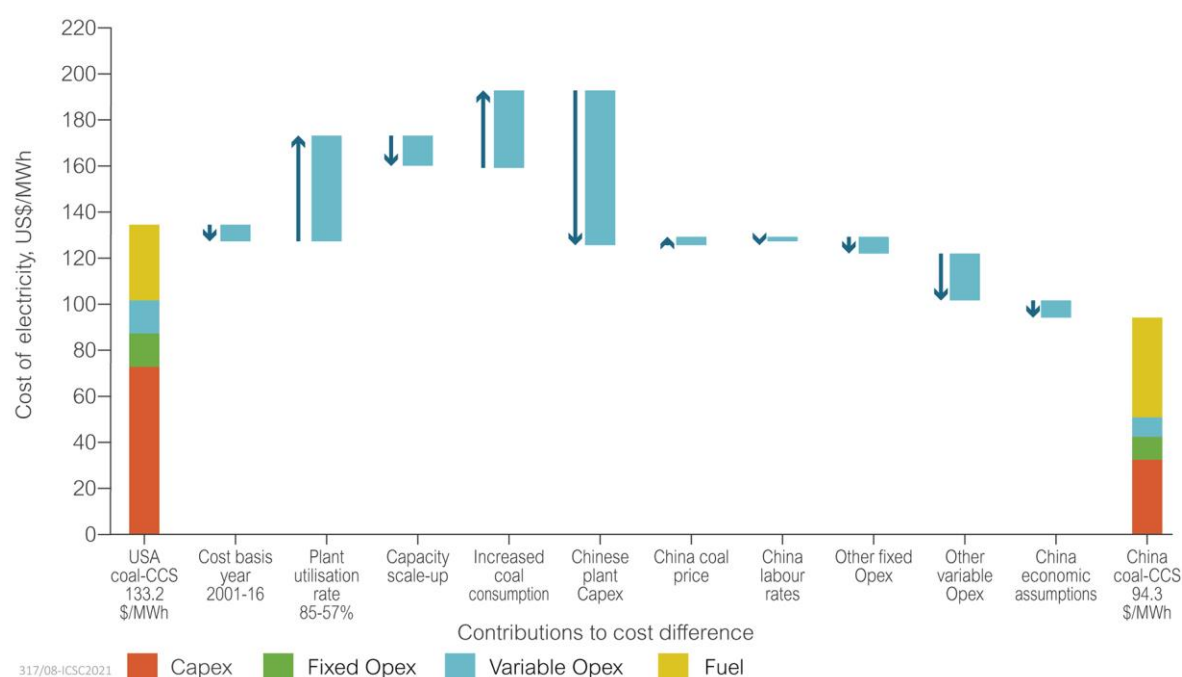


Figure 8 Conversion of NETL baseline costs for a supercritical coal plant with CCS to a Chinese context (Singh and others, 2018)

In 2016, the NETL itself addressed retrofit costs in the USA context. ‘Eliminating the derate of carbon capture retrofits’ comprised a detailed techno-economic study of CCS retrofits to a generic 550 MW (net) subcritical coal-fired power plant (NETL, 2016). The report examines three different approaches to providing the thermal energy required by the capture process: steam extraction from the power plant steam cycle; addition of an open-cycle gas turbine (OCGT) auxiliary plant; and addition of a CCGT auxiliary plant. Again, this earlier study actually calculates a first-year cost of electricity (COE), rather than a levelised cost (the two metrics become equivalent if inflation is set to zero). The power plant is assumed to be fully depreciated, so it contributes no capital costs to the calculation. Relative to an unabated COE of 44.2 \$/MWh, the ‘steam extraction’ CCS case shows the largest increase to

113.6 \$/MWh, while addition of a CCGT cogeneration limits the cost increase to only 77.7 \$/MWh (78% increase). However, the cases with cogeneration units also have a higher emissions intensity than the steam extraction case, as emissions from the gas-fired plant are not captured (see Section 4.2.2 for comparison in terms of CO₂ emitted).

Several cost studies have been conducted for CCS retrofits in India, and are briefly reviewed in a 2021 report prepared for the IEA Coal Industry Advisory Board by the ICSC (Adams and others, 2021). However, many of these studies are based on a generic plant cost model produced by Carnegie-Mellon University known as the Integrated Environmental Control Model (IECM). As such, while some project costs are derived on a site-specific basis, equipment costs may not accurately reflect the Indian context. A 2017 study by Singh and others uses the IECM to cost CCS retrofits at seven Indian coal plants of varying characteristics, and obtained an average increase in LCOE of 110% for the retrofit case, which is in good agreement with the India case in IEAGHG, 2018 (Singh and others, 2017).

4.1.3 Comparisons with other forms of low-carbon generation

International

The falling costs of wind and solar power over the past decade have been widely noted. According to the International Renewable Energy Agency (IRENA), the global average of solar photovoltaic (PV) project LCOEs has fallen by 85% from 2010 to 2020, while offshore wind and onshore wind have fallen by 48% and 56% respectively (IRENA, 2021). Goldman Sachs analysis presents similarly sharp declines in Figure 9, although costs are anticipated to level off from 2020 onwards (Della Vigna and others, 2020). Solar power is now the cheapest form of power generation in many regions, usually closely followed by onshore wind. While offshore wind remains somewhat more costly in regions such as the USA and India, the IEA estimates LCOEs even below that of onshore wind in the EU (where it has seen most widespread deployment) (IEA, 2020a). Some studies differentiate between utility-scale solar PVs, which are more cost effective, and ‘rooftop’ residential installations, which are widely deployed in many regions but typically have higher LCOEs.

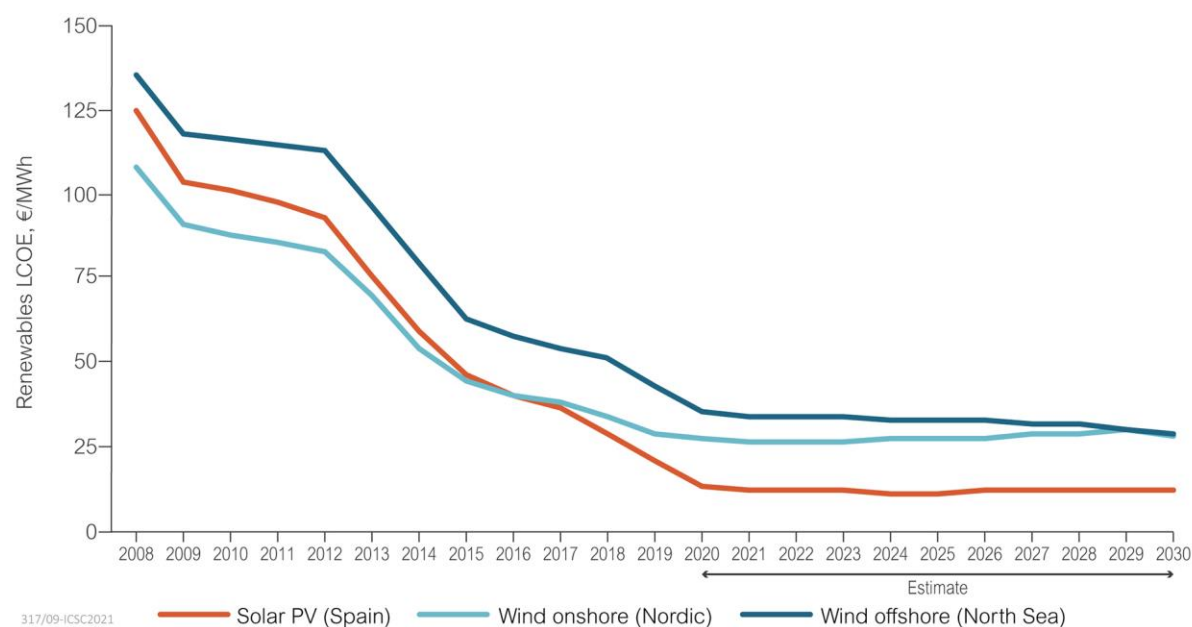


Figure 9 Historic and projected cost reduction of wind and solar power (Della Vigna and others, 2020)

There are relatively few studies which provide direct comparison of CCS power costs with renewables and other low-carbon forms of electricity generation using the same cost basis and assumptions. However, a key international reference is provided by the IEA and the Nuclear Energy Agency's 'Projected Costs of Generating Electricity', published every five years based on cost data submitted by member countries, and which presents LCOEs for lignite, hard coal and gas-fired power plants with CCS in its 2020 edition (Figure 10) (IEA/NEA, 2020). This study is based on applying a standardised methodology to cost input data provided by a range of OECD countries and a smaller group of non-OECD countries, which cover a range of plant sizes and types for each technology category. It applies capacity factors of 85% for all nuclear and fossil fuel-based plant and applies a CO₂ price of 30 \$/t for all countries over the lifetime of the plant. All cost figures are in 2018 \$.

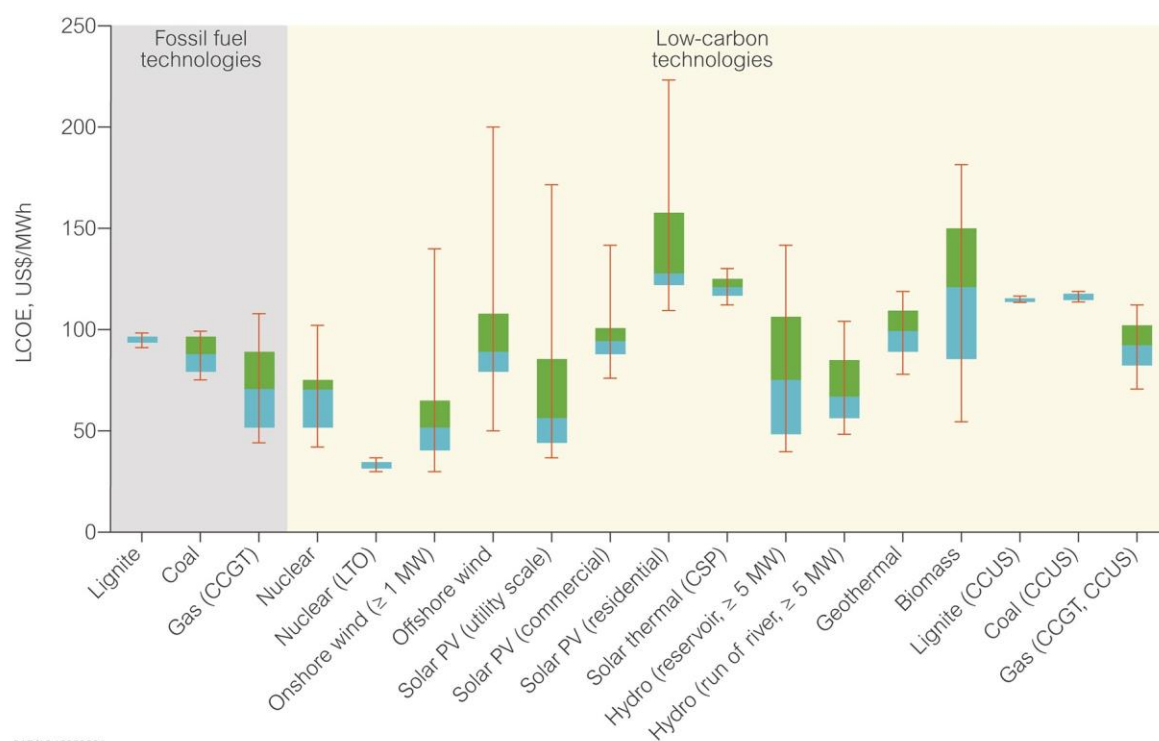
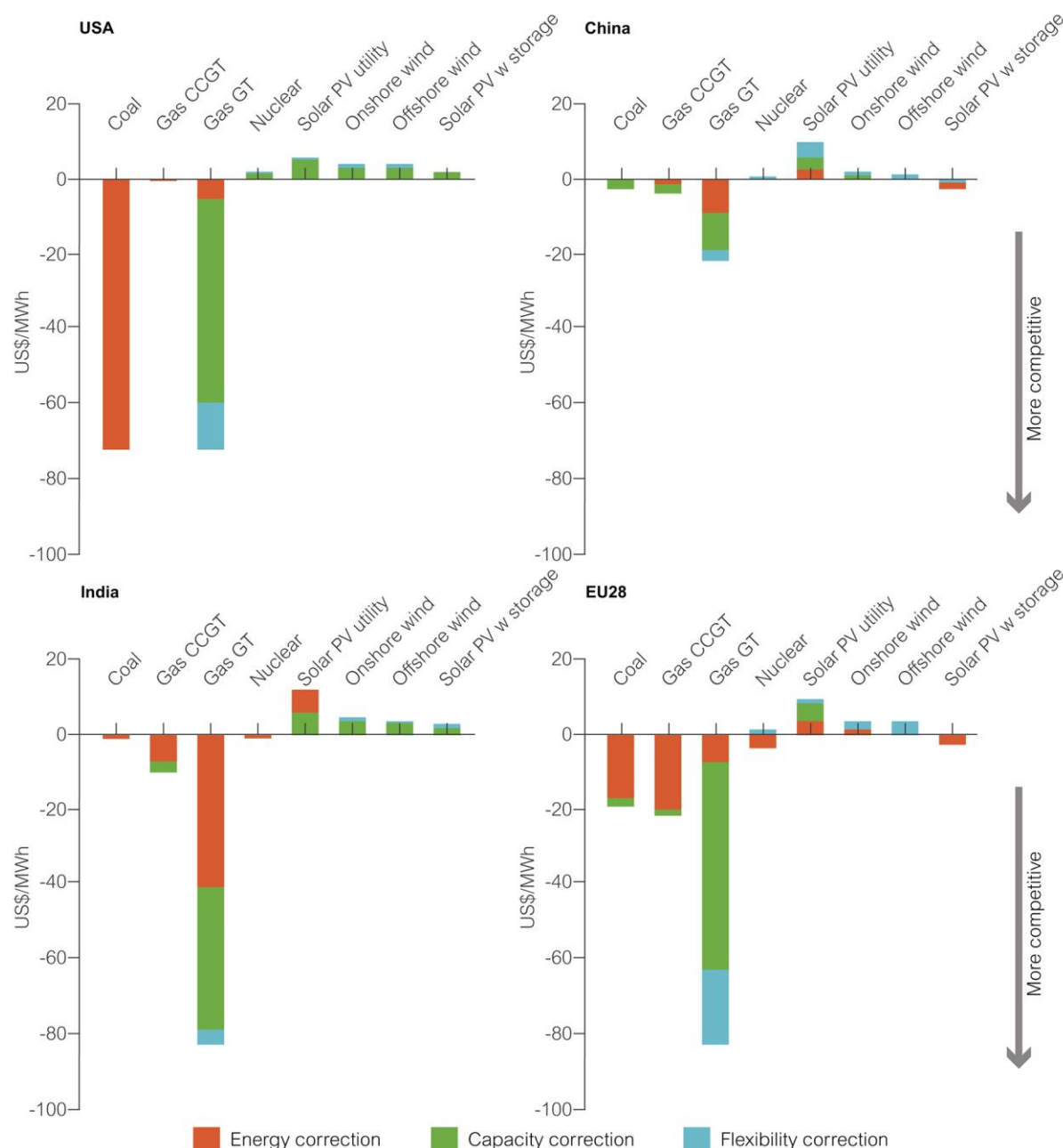


Figure 10 LCOE ranges by technology type (IEA/NEA, 2020)

However, only two countries submitted data for CCS (USA and Australia), so the cost range obtained is likely to be less representative of the sample size than most other technologies considered. Notwithstanding this limitation, the study provides an average LCOE of around 115 \$/MWh for coal-fired plant with CCS, and an estimate of 91 \$/MWh for a CCGT-CCS. This compares with a median cost estimate of 95 \$/MWh for offshore wind, 52 \$/MWh for onshore wind, and 70 \$/MWh for utility-scale solar PV. The cost range for all renewable energy sources is noticeably higher than the range of LCOEs presented in the IEA's 2020 World Energy Outlook, with offshore wind showing the most significant disparity. On the other hand, nuclear power is indicated as much more costly in the World Energy Outlook (IEA, 2020a).

Lower LCOE estimates for coal with CCS are associated with cases featuring lower-cost fuel and, in particular, sensitivity cases using a low discount rate of 3%, which effectively reduces the cost of capital (not shown in Figure 10). Australia's submitted costs for a supercritical lignite-fired plant with CCS generate an LCOE as low as 81 \$/MWh in the low discount rate case, while the lowest US-based estimate (hard coal, 3% discount rate) comes in at 95 \$/MWh. On the other hand, a discount rate of 10% results in coal-CCS costs as high as 140 \$/MWh in the USA.

The study also determines the carbon price at which the LCOE for CCS-equipped plants would become competitive with unabated plants, indicating that the CCS plant is favoured at a price of 60 \$/t for coal-fired plants and 90 \$/t for gas-fired plants.



By 2025, value adjustments are already important in evaluating the competitiveness of solar PV without storage, and remain important to peaking plants like open-cycle gas turbines

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Figure 11 Value-adjusted LCOE for different technologies and regions (IEA/NEA, 2020)

As discussed in Section 2.2, the IEA have introduced a ‘value-adjusted LCOE’ (VALCOE) to better account for the non-energy attributes provided to the grid by different generating technologies, including capacity and flexibility. The Projected Costs of Generating Electricity provides VALCOE estimates based on projected demand profiles, installed capacity mix, and fuel prices for 2025 in the 2019 World Energy Outlook’s Stated Policies Scenario, which projects likely changes to the energy mix based on announced policies (Figure 11). As dispatchable thermal power plants still predominate in most regions by this date, providing adequate capacity and flexibility to the grid, the adjustments made to the LCOE are mostly small. However, OCGTs become much more competitive under

VALCOE, due to their role in providing electricity when it is most valuable (peak times) and their activity in ancillary service markets. Coal and CCGT plants see little adjustment under VALCOE, as they already operate with high capacity factors, but they are credited for provision of system adequacy and some flexibility services – this is most apparent in the EU. VRE sources see some upwards cost adjustment due to their limited contribution to resource adequacy and, in the case of solar PV, poor alignment with demand profiles. In the absence of specific data for CCS-equipped fossil fuel plant, the likely adjustments for these plants can only be inferred from the unabated coal and gas-fired cases. The size of the VALCOE adjustments can be expected to increase over time as penetration of renewables increases.

USA

The USA-based EIA publishes an annual review of electricity generation costs to support its Annual Energy Outlook (EIA, 2019, 2020). From 2016 to 2019, this analysis included cost estimates for coal and gas-fired plant with CCS, but this was removed in 2020, following a 2018 ruling by the Environmental Protection Agency that CCS was no longer to be considered the ‘best system of emission reduction (BSER)’ for coal-fired power plant under the New Source Performance Standard (NSPS) (instead basing the standard on the most efficient steam cycle). As shown in Figure 12, the 2019 analysis includes CCGT with CCS and coal-fired plant with CCS capturing either 30% of emissions or 90% of emissions. The additional ‘partial capture’ case for coal is due to this level of capture being sufficient to meet the former NSPS. However, a higher cost of capital (3-percentage point increase in interest rate) was applied to this case and all unabated fossil fuel plant cases in order to reflect the risk of future, more stringent CO₂ emissions legislation. In the 2019 publication, costs are estimated for plants to be commissioned in 2021, 2023 and 2040, but CCS does not feature in the 2021 analysis.

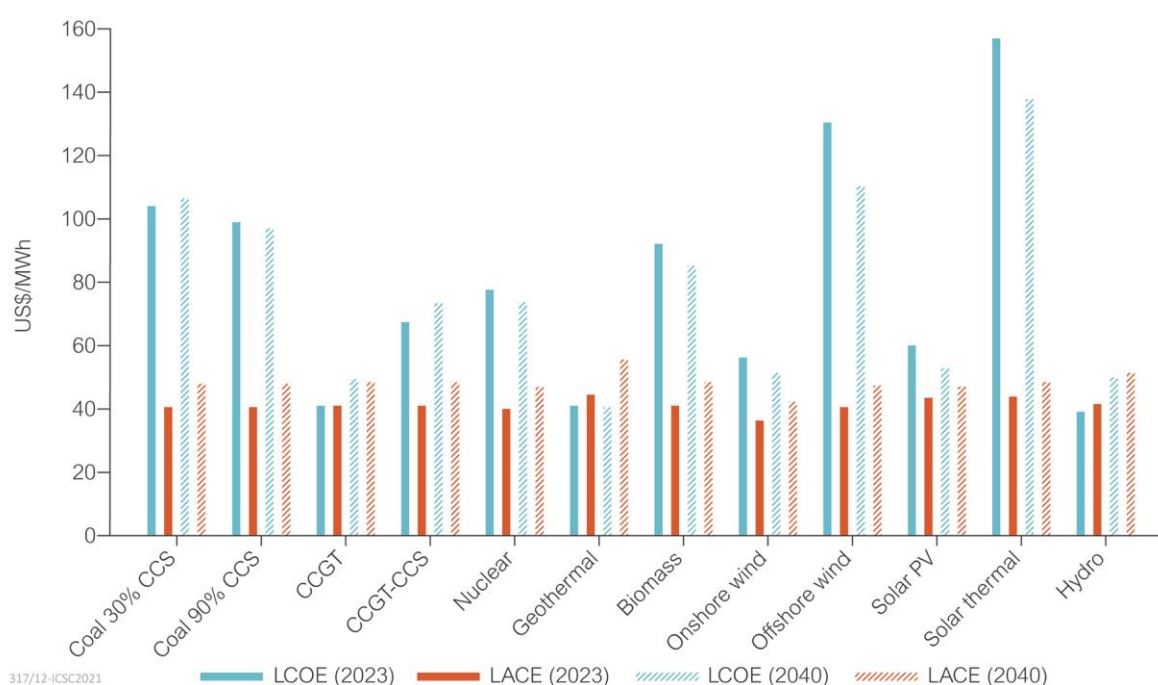


Figure 12 LCOE and LACE of different technology types in 2023 and 2040 (EIA, 2019)

The study actually estimates costs for each technology across the 22 supply regions used in the agency's National Energy Modelling System (NEMS), using appropriate adjustment factors for regionally varying parameters such as labour and material costs. The final, national LCOE values are presented both as a simple average over all regions and a 'capacity-weighted' average, which gives greater weighting to regions which are deploying more capacity of a given technology. A 30-year cost recovery lifetime is applied for all technologies, and a real after-tax discount rate of 4.2%. All costs are estimated by Sargent & Lundy for the EIA, with the coal-CCS cases based on a 650 MW unit with a solvent-based post-combustion capture process.

For plants entering service in 2023, CCGT with CCS has a 31% lower LCOE than coal with 90% CCS. Coal-CCS is almost twice the cost of onshore wind and over twice the price of solar PV but, unlike in the international analysis, its LCOE is below that of offshore wind, which is much less established in the USA.

The study also provides values for levelised avoided cost of electricity (LACE), which is a metric developed by the EIA to estimate the actual income a generator type might derive from the electricity market (see Section 2.2). On this basis, a high value represents better plant economics, and all generation sources are much more closely matched. A CCS-equipped power plant competes more closely with VRE sources, as the average (unweighted) LACE for coal-CCS with 90% capture is marginally higher than onshore wind and below solar PV. CCGT-CCS is able to draw 7% more value (on average) from the market than coal-CCS, presumably due to more flexible operation. Offshore wind provides better value than onshore wind, likely due to its higher capacity factors.

For plants entering service in 2040, there is a slight reduction in the cost of coal-CCS (90% capture) and an increase in the cost of both unabated CCGT and CCGT-CCS. This increase can be attributed to a projected increase in gas prices, while coal prices remain more stable. VRE sources all see some cost reduction over this period, although offshore wind remains more costly than both forms of CCS. The LACE of both coal and CCGT plant with CCS see an increase of 17.5% over 2023, but similar increases are also observed for both forms of wind power, despite the larger proportion of VRE on the grid at this future date. On the other hand, the LACE of solar power increases by less than 8%, presumably due to heavy deployment and the resulting decline of electricity market value during daylight hours.

Australia

LCOE estimates for Australia's National Electricity Market are provided in the annual 'GenCost' report, produced since 2018 by the Commonwealth Scientific and Industrial Research Organisation (CSIRO) and the Australian Electricity Market Operator (AEMO) (Graham and others, 2020). The 2020-21 edition of this report determines LCOEs for plants commencing operation in 2020, 2030, 2040, and 2050, with results for the 2030 analysis presented in Figure 13.

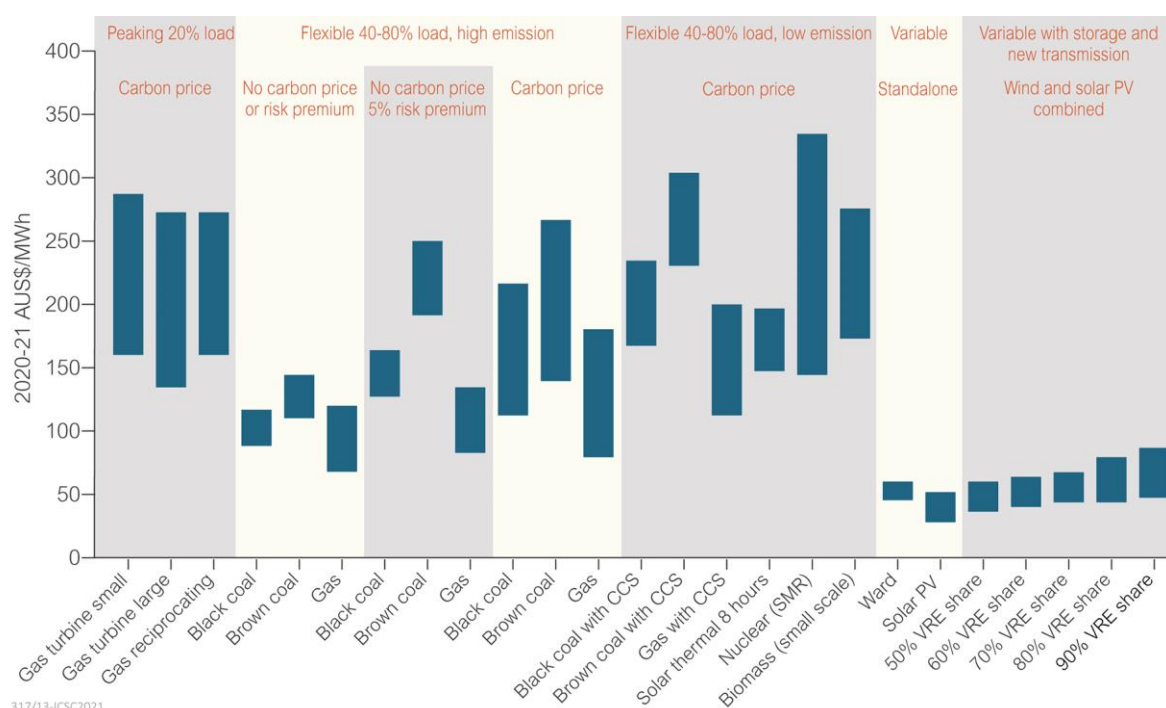


Figure 13 LCOE estimates for Australia in 2030 (Graham and others, 2020)

The cost study is accompanied by projections of the future energy mix using AEMO's energy market model, which are also used to add system integration costs for VRE generation. A combined adjusted LCOE for wind (onshore) and solar PV is calculated for varying levels of overall VRE penetration on the grid, in which the difference between the associated system costs such as storage and additional transmission are calculated relative to a 'business as usual' scenario (under which VRE deployment is allowed to proceed on a least-cost basis to 34% of generation). As indicated in Figure 13, VRE costs increase by roughly 50% when moving to 90% generation, but remain well below other low-carbon options.

The range of values shown for the fossil fuel-based sources are associated with a range of input parameters, including capacity factors (60–80%), fuel prices, cost of capital, and carbon price. In the lowest-cost case, the carbon price follows a trajectory from 18.1 to 64.6 AU\$/t in 2050 (13 to 47 \$/t), while in the highest-cost case it increases from 30.7 to 386.7 AU\$/t over the same period (22 to 282 \$/t). Similar to the IEA study, a 5-percentage point risk premium is added to the cost of capital (discount rate) for unabated fossil fuel plant.

In 2030, CCGT-CCS is again the lowest cost variety of CCS-based plant, with a central LCOE of 158 AU\$/MWh (115 \$/MWh), compared to 202 AU\$/MWh for black (bituminous) coal-fired plant with CCS (147 \$/MWh). The average LCOE of CCS plant firing Australian brown coal (lignite) is higher still, at 267 AU\$/MWh (195 \$/MWh). These costs represent the largest differential with VRE costs of the studies reviewed in this report, which is probably due to the relatively high cost of construction for large infrastructure projects in Australia, the effect of a high carbon price on residual

emissions, and the country's favourable wind and solar resources. The cost range of CCS-equipped plant does not see very significant changes over the start years considered from 2020 to 2050, with the lower limit tending to slightly fall (except for the lignite case) while the upper limit increases. This increase in the upper limit is largely associated with the higher cost of residual emissions at the high future carbon prices considered (in the case of lignite, this negates cost reductions even under the lower carbon price trajectory).

United Kingdom

The UK government provides an annual cost analysis of relevant power generation technologies, including CCGT with CCS (but not coal). In the 2020 analysis, an efficient 'H-Class' CCGT with CCS has the same LCOE as an unabated unit (85 £/MWh (117 \$/MWh)) due to savings in CO₂ costs (based on projected prices for the EU Emissions Trading System until 2030, and then a linear increase from 2030 to 2050) (BEIS, 2020). The CCS-equipped gas plant is nearly 50% more costly than offshore wind, or 93% more expensive than large-scale solar generation.

TABLE 1 A SUMMARY OF PARAMETERS USED IN THE MAIN COST STUDIES REVIEWED

Study	Discount rate	Cost recovery period (years)	Utilisation factor	Carbon price	T&S cost	Currency	Start year	LCOE coal CCS	Cost increase over unabated coal
IEA/NEA (2020)	7%	30 (gas) 40 (coal)	85%	30 \$/t	Not stated	2018 \$	2025	115 \$/MWh	29%
EIA (2019)	4.2% (7.2% for unabated fossil)	30	85% (coal) 87% (gas)	None	0	2018 \$	2023 (and 2040)	98.6 \$/MWh	No unabated coal case
Graham and others (2020)	5.99% (+5%pt for unabated fossil)	25 (gas) 30 (coal)	60–80%	18.1 and 30.7 AUS\$/t (2020)	1.9 AUS\$/MWh (gas) 4.2 AUS\$/MWh (coal)	2020-21 AUS\$	2030 (and 2020, 2040, 2050)	167–238 AUS\$/MWh	23%
NETL (2019)	6.54%	30	85%	0	10 \$/t	2018 \$	2023	114.3 \$/MWh	77%
IEAGHG (2018)	8%	25	90% (coal) 93% (gas)	0	10 €/t	2016 €	–	87.9 €/MWh (mean over all cases)	93% (mean increase)
IEAGHG (2020)	8%	25	90% (coal) 93% (gas)	0	10 €/t	2018 €	–	97.3 €/MWh (Netherlands case)	83%
Wood (2018)	8.9% (CCS cases)	25	90%	Increases from 22.6 to 223 £/t	19 £/t	2017 £	2025	93.3 £/MWh	No unabated coal case

4.1.4 Summary

- The LCOE of supercritical coal plant with post-combustion CCS is typically found in the range of 90–130 \$/MWh for locations in the USA and Western Europe.
- The LCOE of CCGT plant with post-combustion CCS is typically found in the range 70–100 \$/MWh for locations in the USA and Western Europe.
- Lower costs for coal-based CCS (both new-build and retrofit) cases have been estimated for China, in the range 80–100 \$/MWh.
- CCGT with CCS is more competitive on an LCOE basis than coal-CCS in most regions studied, with the notable exception of China.
- The LCOE of a new coal or gas plant with CCS is typically 70–100% greater than an equivalent unabated plant (without considering a carbon price).
- Retrofit CCS costs are found to be somewhat lower, but there is considerable variation in how retrofit LCOE is calculated.
- Using the same cost estimation basis in OECD countries, LCOEs of coal-CCS and gas-CCS are generally 1.5–3 times higher than those of solar power and onshore wind.
- Cost of electricity metrics which adjust for system costs reduce the gap between VRE and CCS-based generation, but not significantly for the levels of VRE deployment studied.

4.2 THE COST OF CO₂

4.2.1 Reducing the cost of capture

For specific operating and planned CCS power projects, the cost of capturing a tonne of CO₂ is often a more publicly available metric than the cost of generating electricity, which is considered commercially sensitive information. The GCCSI have usefully collated estimated or reported CO₂ capture costs (including CO₂ compression, but not T&S) for the two operating coal power plants with CCS, as well as cancelled and currently planned projects which have completed feasibility studies (Figure 14) (GCCSI, 2019). Nearly all projects shown represent retrofits to existing coal power plants.

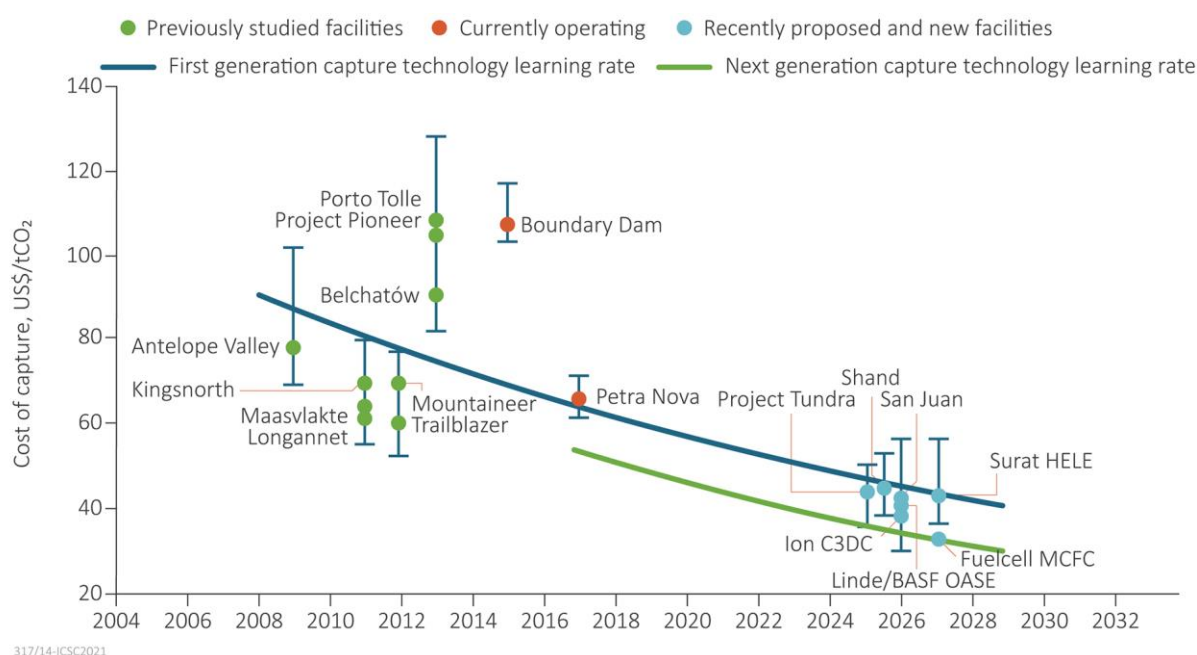


Figure 14 Reduction in the cost of capture for coal power CCS retrofits (GCCSI, 2019)

The figure highlights a clear trend of declining costs for coal-CCS, even though nearly all of the projects listed utilise similar capture technology, in the form of post-combustion capture with amine-based solvents (the fuel cell-based project is an exception). These cost reductions are therefore associated with various process and project optimisation advances which have been achieved for this technology and are further detailed in reports such as Kelsall (2020) and Kearns and others (2021). Cost reductions can broadly be categorised as:

- **Learning by doing** – experience from the operating projects has enabled process and operating improvements, more efficient staffing, and reduced process contingencies (such as over-sized equipment);
- **Economies of scale** – larger plants can access lower specific costs (per tonne CO₂) as many equipment costs do not scale linearly with output (for example, balance of plant equipment);
- **Modular construction** – significant cost optimisation can be achieved through off-site fabrication of capture plant in smaller modules, which can then be assembled on site;
- **Technical advances** – new solvent formulations can reduce operating costs through reduced solvent losses and (to a lesser extent) reduced energy penalty; and
- **Improved financing** – access to lower cost financing is possible when adequate policy incentives, such as the 45Q tax credit in the USA are present, providing investor confidence.

The GCCSI's 'Technology readiness and costs of CCS' (Kearns and others, 2021) further analyses the key factors which affect the cost of CO₂ capture across all applications, including CO₂ partial pressure in flue gas, scale of the plant, and interest rates. Costs are calculated based on use of the standard 'baseline' solvent monoethanolamine (MEA), and are intended to reflect consistent trends rather than absolute costs.

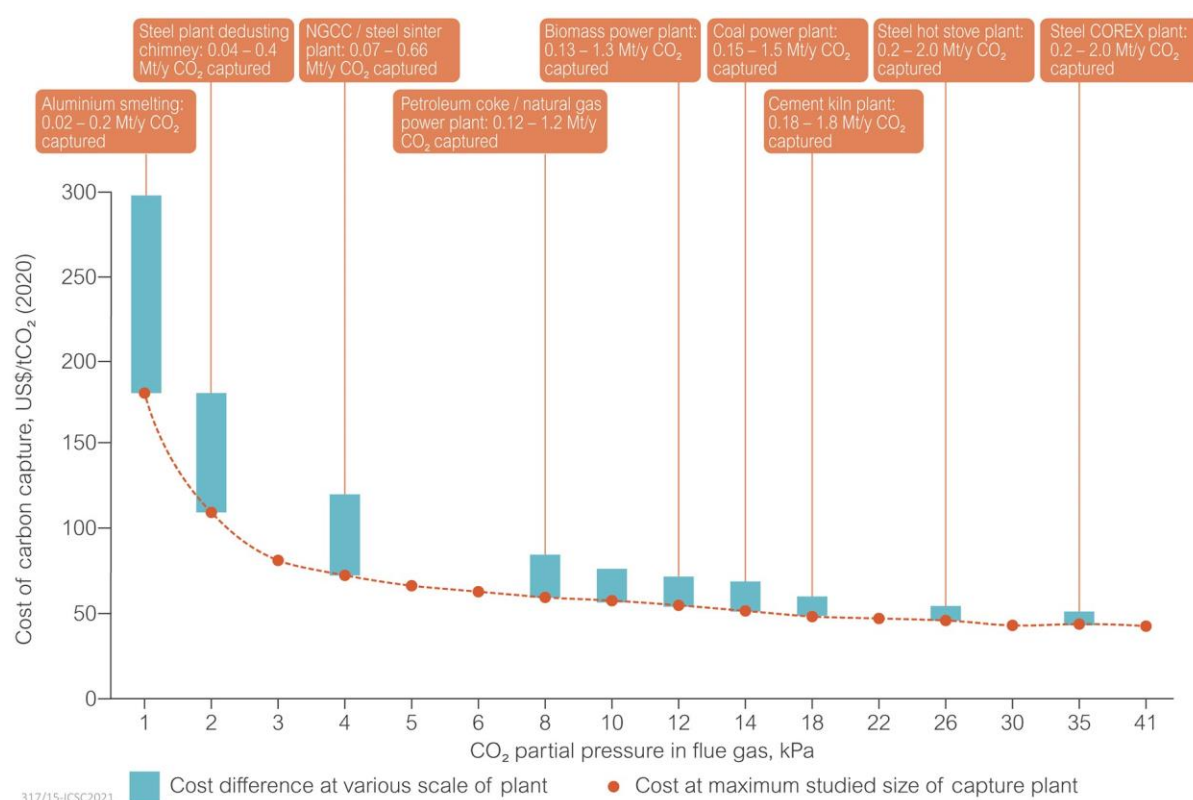


Figure 15 The effect of CO₂ partial pressure and facility scale on the cost of capture (Kearns and others, 2021)

Figure 15 highlights that CCS applied to CCGT plant will carry higher CO₂ capture costs than coal plant applications, due to the much lower partial pressures of CO₂ found in CCGT flue gas (around 4%). Not only is it more thermodynamically challenging to separate CO₂ from this less-concentrated source, but a greater volume of gas must be processed to obtain the same quantity of CO₂, meaning larger equipment and a greater capital investment per tonne of CO₂. Increasing the scale of the power plant or reducing the interest rate can both allow significant reductions in capture cost, and both effects are more pronounced for low partial-pressure streams such as CCGT flue gas.

The IEA report ‘The role of CCUS in the clean energy transition’ also provides a range of 50–100 \$/t for capture from all power plants in 2019, which is in agreement with the range covered by pulverised coal plant and CCGT in the GCCSI report (IEA, 2020b).

4.2.2 Cost of CO₂ avoided

As defined in Section 3.3, the cost of CO₂ avoided expresses the cost of each tonne of CO₂ mitigated by a CCS-equipped plant compared with an unabated fossil fuel plant of the same net power output. It always includes transport and storage costs. The most recently published NETL cost baseline studies for fossil energy plants refer to this avoided cost as the ‘breakeven CO₂ emission penalty’, for which results are shown in Figure 16 (together with the cost of capture). In addition to the capture cost advantage over CCGT-CCS already discussed, coal-CCS plant appears much more competitive on a CO₂ avoided basis due to the higher CO₂ intensity of the reference unabated coal-fired plant (more

emissions are avoided by 90% capture). A supercritical pulverised coal unit has an avoided cost of 73.5 \$/t, compared to 102.2 \$/t for the gas-fired case.

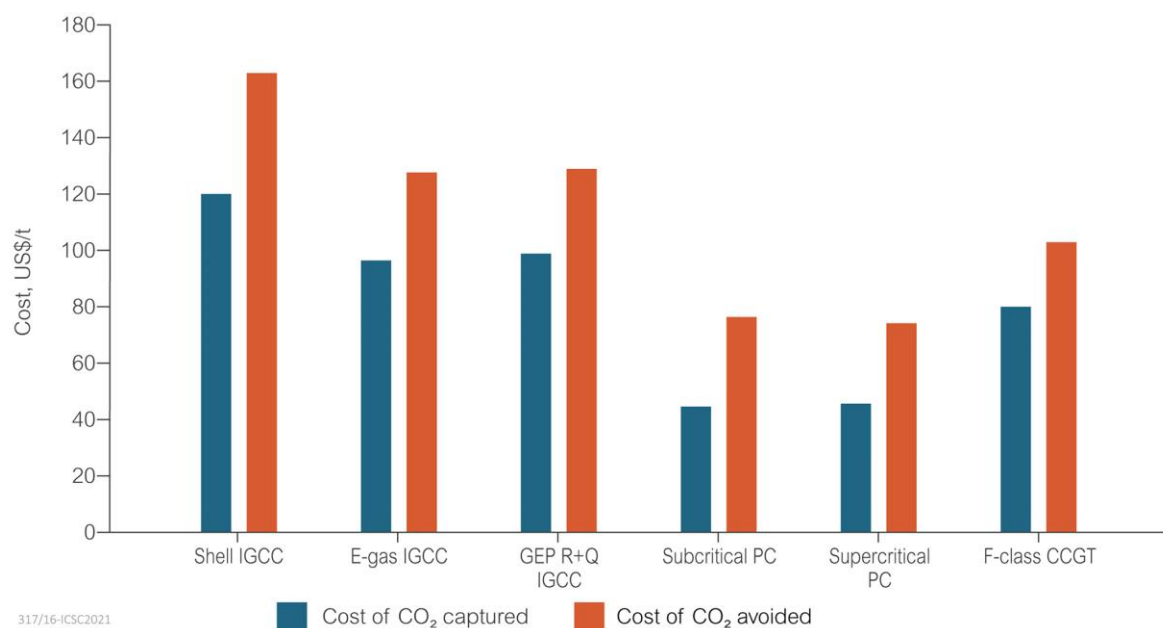
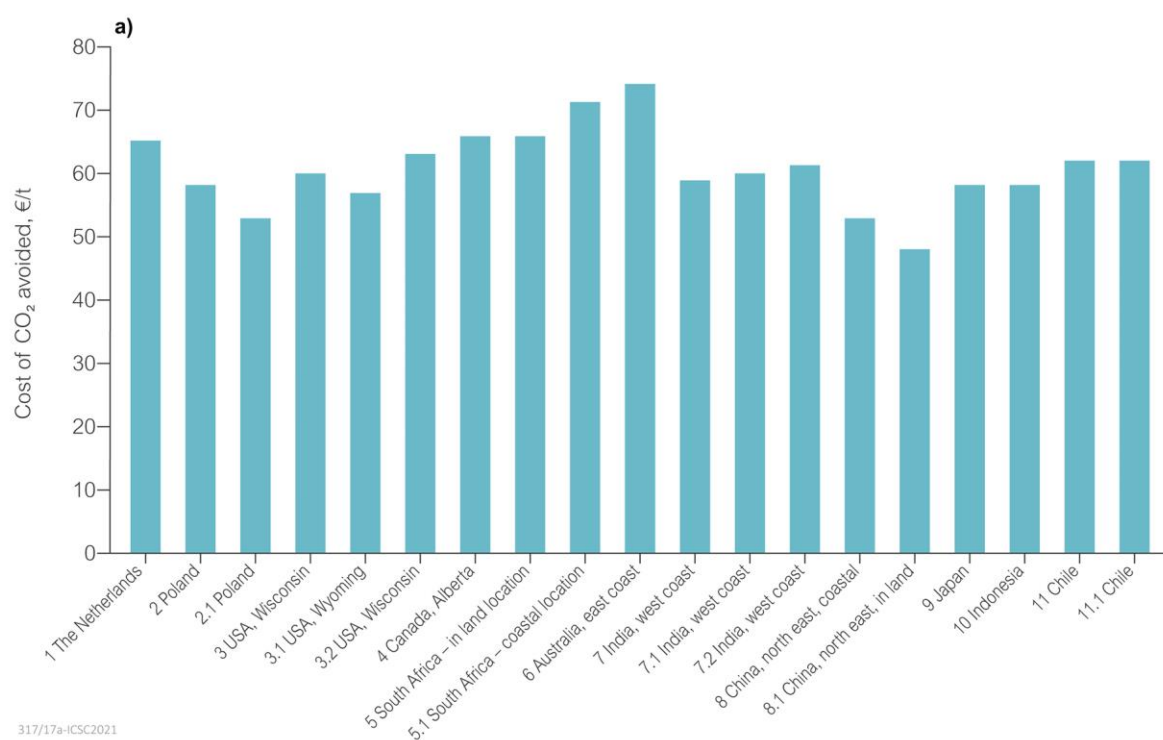


Figure 16 The cost of CO₂ captured and avoided for new CCS plants (NETL, 2019)

The IEAGHG study ‘Effects of location on CCS cost’ also provides a ‘cost of CO₂ avoided’ (CAC), shown in Figure 17 for all coal-fired cases. When converted to \$, the value for the USA cases shows reasonable agreement with the NETL study. As for the LCOE analysis, the inland location in China provides the lowest-cost CO₂ abatement value of 48 €/t (56 \$/t).



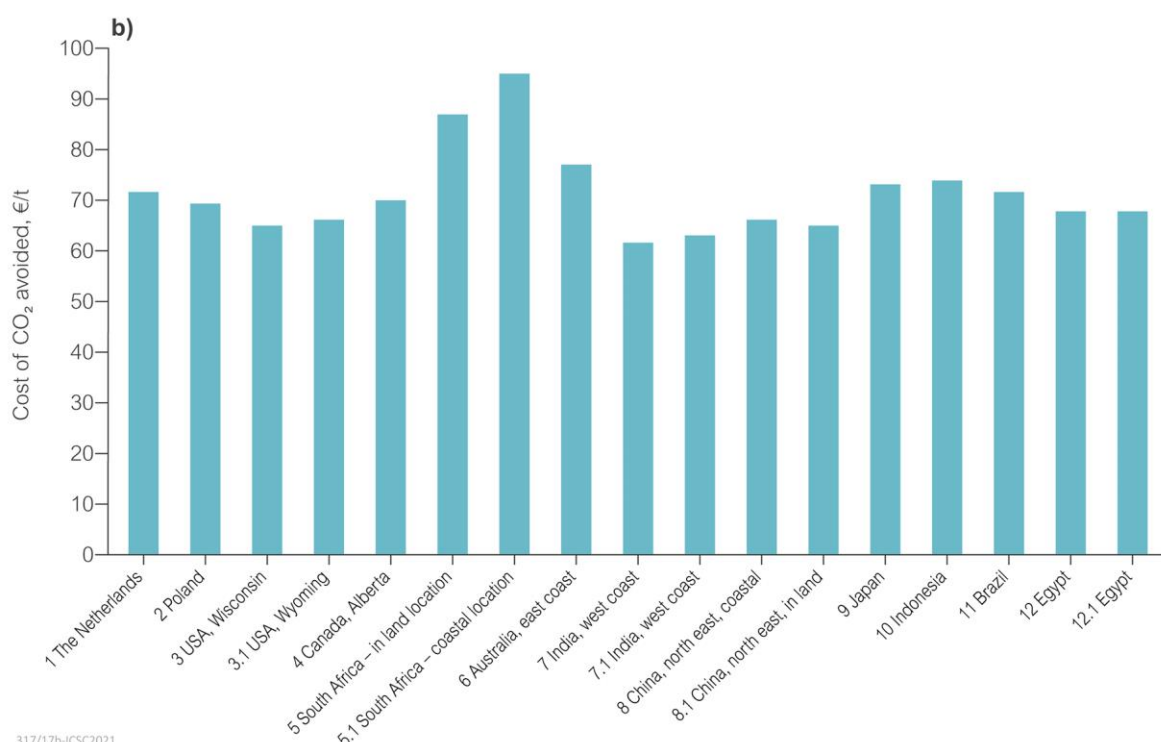


Figure 17 CO₂ avoided costs for (a) SC PC cases and (b) CCGT cases (IEAGHG, 2018)

The costs of CO₂ avoided for CCGT-CCS are again slightly higher than coal cases, but show a different variation between the locations studied, due to the high dependence on natural gas prices in each region. For this reason, South Africa has by far the highest cost, and China is less competitive than it is for coal-based plant.

In the 2020 update of costs for the reference Netherlands case, the cost of CO₂ avoided for coal-CCS (90% capture) sees a marginal increase of 3%, while for CCGT-CCS it decreases by the same amount (IEAGHG, 2020). Increasing the capture rate of the coal-fired case to 99% results in an increase of only 4.3% in the cost of CO₂ avoided, demonstrating that the increase in absolute capture costs is mostly outweighed by the additional CO₂ avoided. Similarly, the high capture rate case (98.5%) for CCGT-CCS leads to only a 5% increase in the cost of CO₂ avoided.

Retrofit cases

CO₂ avoided costs can be effective for representing the cost of CCS retrofit projects, as the avoided emissions can be easily identified as the CO₂ which would be emitted by the unabated plant over its remaining lifetime. However, there are some challenges associated with calculating avoided costs for retrofit cases. First, as for LCOE calculations in Section 4.1.2, an assumption must be made on how the power plant capital is to be treated. Second, the retrofitted plant will usually generate less electricity than the original power plant, so the two cases are not directly comparable. Some studies simply disregard this difference, rendering the ‘avoided cost’ similar to a cost of abatement (*see* Section 3.3). Alternatively, the generation deficit can be charged to the retrofit case according to the wholesale price of electricity.

Retrofit estimates can be made for generic plant cases, but are more frequently applied to real plants, allowing more accurate costing of elements specific to the site (such as plant size, efficiency, and flue gas characteristics). In particular, CO₂ transport costs can be calculated based on the actual distance to suitable CO₂ storage (rather than taking a general – usually favourable – estimate), which often has a significant effect on total costs.

The 2016 NETL report examining the cost of coal-CCS projects in the USA (see Section 4.1.2) obtains breakeven CO₂ sales prices (cost of capture) and breakeven CO₂ emissions penalties (cost of CO₂ avoided) shown in Figure 18. In this analysis, the cases which employ gas-fired cogeneration plant (OCGT or CCGT) to power the capture plant actually produce more net power than the original unabated coal plant, while the retrofit case based on steam extraction from the coal plant generates less (Retrofit Case 0 in the figure). This difference in power output is credited or charged to each case's cost of electricity at a rate of 60 \$/MWh when calculating the CO₂ prices. Owing primarily to the much lower CO₂ intensity of the steam extraction retrofit (which has no unabated emissions associated with the gas-fired plant), the cost of CO₂ avoided for this case is much more competitive at 78.8 \$/MWh, compared with 157.2 \$/t for the plant with CCGT cogeneration (Retrofit Case 2). This analysis highlights the significant effect of the choice of basis on which to compare different capture configurations; a low cost of capture or cost of electricity may not equate to the most cost-effective CO₂ reduction, if the carbon intensity of the whole system is increased.

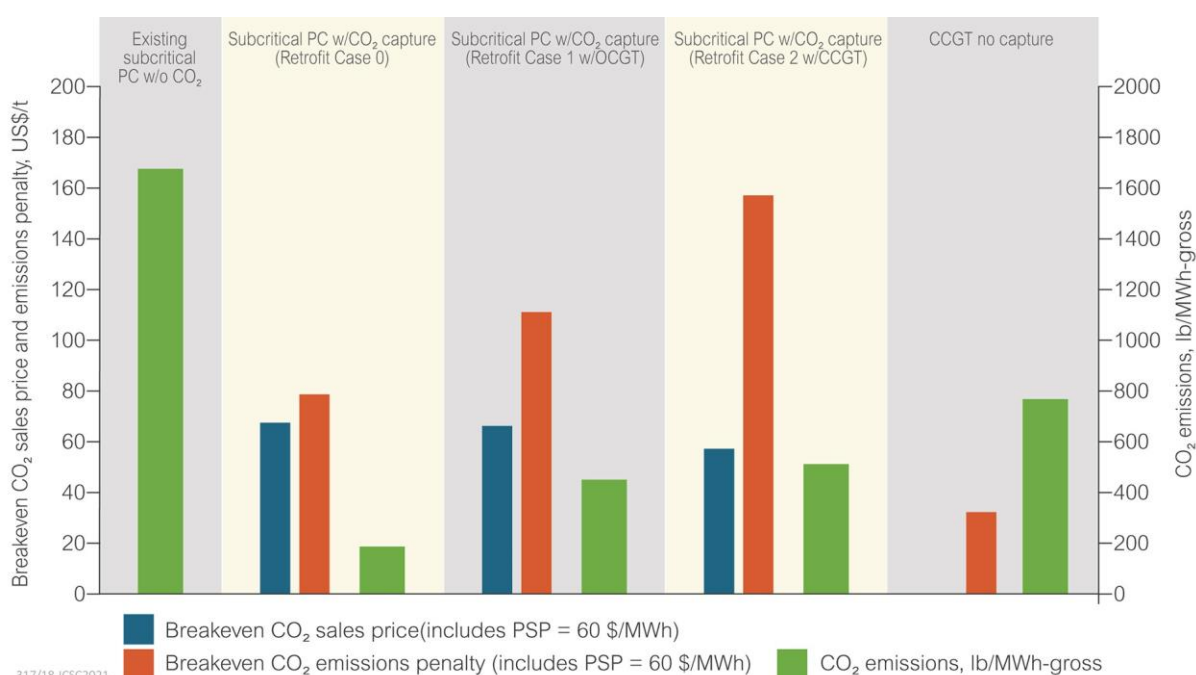


Figure 18 Cost of capture and CO₂ avoided for PC plant cases (NETL, 2016)

Given the large scale of recent coal plant construction which has taken place in Asia, and in China in particular, much of the interest in the cost of CCS retrofits has focused on this region. As shown in Section 4.1.1, it appears that CCS costs are likely to be relatively low for new plants in this region, and retrofit costs have the potential to be even lower. In 2019, the National Institute of Clean and

Low-Carbon Energy (NICE) conducted an analysis of the cost of retrofitting the coal power units belonging to Shenhua Group (part of China Energy) (Singh and others, 2019). This study highlights the huge variation in retrofit costs between different power plant sites, as well as the potential for very low CO₂ avoided costs at the most promising locations. Of 25 power plants (56 GW) studied, responsible for 260 MtCO₂/y in 2016, the study found 25% of emissions could be avoided for less than 80 \$/t in a ‘baseline’ cost case or for less than 32 \$/t in an optimised ‘affordable capture case’ (Figure 19). This lower-cost case is primarily based on application of incentives available in China’s regulated electricity market, including internal coal pricing by utilities, accelerated plant depreciation (reducing the remaining capital cost for older plants), and preferential plant dispatch to increase operating hours. The figure indicates how many plants incur large total costs due to being far removed from potential storage sites, with T&S costs rising to 360 \$/t. This analysis includes the capital cost of the power plant in proportion to the extent of its depreciation at the time of retrofit. However, it does not appear to correct for the reduction in net electricity output in the retrofit cases.

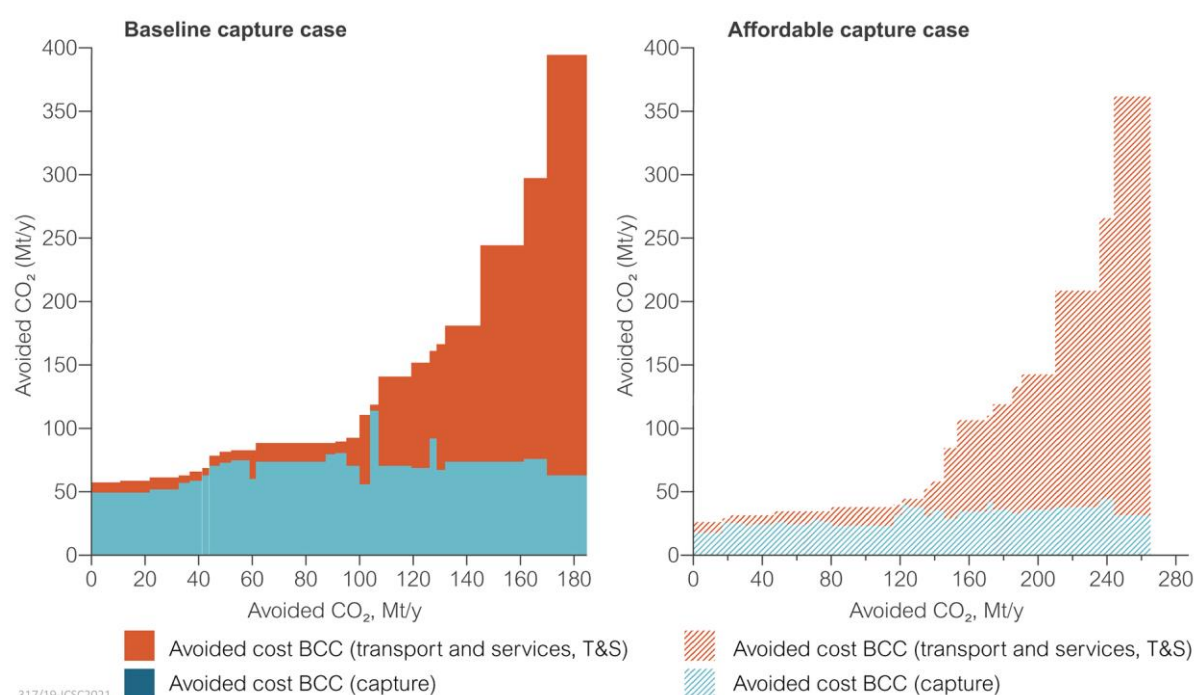


Figure 19 Marginal cost curves for CCS retrofits to the Shenhua fleet under a baseline cost case (left) and an affordable cost case (right) (Singh and others, 2019)

The authors also extrapolate the analysis to a larger proportion of the Chinese coal fleet by comparison with a study conducted by the IEA in 2016, which looked at 560 GW of coal capacity with a reduced level of plant-specific detail (IEA, 2016b). Although good agreement was found over most of the cost curve, the more recent work estimated much lower transport and storage costs at the high-end of the range. Assuming this lower-cost ‘tail’ is more accurate, and that ‘affordable capture case’ conditions can be realised, extrapolation of the results for the Shenhua fleet suggest that over 100 Gt/y could have an avoided cost of less than 37 \$/tCO₂.

4.2.3 Cost of CO₂ abated compared with other low-carbon generation

The cost of CO₂ captured and avoided are both used almost exclusively with reference to carbon capture. For comparisons between more diverse forms of low-carbon generation, it is more common to refer to the cost of CO₂ abated, although in many cases this differs very little from the cost of CO₂ avoided. As outlined in Section 3.3, while this term is loosely applied in many contexts, for our purposes it essentially describes the cost of mitigation relative to a ‘business as usual’ scenario. So, rather than comparing the CO₂-cost performance of two alternative forms of new power generation facility, the cost of the new low-carbon generation is compared to the marginal cost of existing generation, which does not include capital costs or other sunk costs such as fixed operation and maintenance (O&M) costs. In this calculation, it is necessary to define the displaced (high carbon intensity) generation, which may be assumed to be a gas plant, a coal plant, or a mix of the two in proportion to the grid’s actual mix. This kind of method can also be applied to emissions from other sectors, usually with the condition that the low-carbon scenario results in the same final output of a product or service.

An example of CO₂ abatement costing for the US power sector is provided by Gillingham and Stock (2018), who used LCOE data from the EIA’s 2018 ‘Annual Energy Outlook’ and a method published by the Clean Air Task Force (2013). The cost of abatement for each new generating technology is calculated as the difference between their respective LCOEs and the marginal cost of displaced coal power generation, which is assumed to be equivalent to the EIA’s ‘levelised variable O&M’ costs for a coal plant with 30% CCS. Given that a plant with 30% CCS will incur CO₂ capture-related O&M costs, this assumption may be questionable, but will not change the relative positions of each technology. The tonnes of CO₂ abated are based on a standard emissions intensity factor for coal of 93.3 kgCO₂/MBtu (0.088 kgCO₂/MJ) and a heat rate of 0.010493 MBtu/kWh (11.1 MJ/kWh). As the EIA do not provide a cost for CCS retrofits on coal, the authors approximated this cost as the new build coal-CCS cost without any fixed O&M costs.

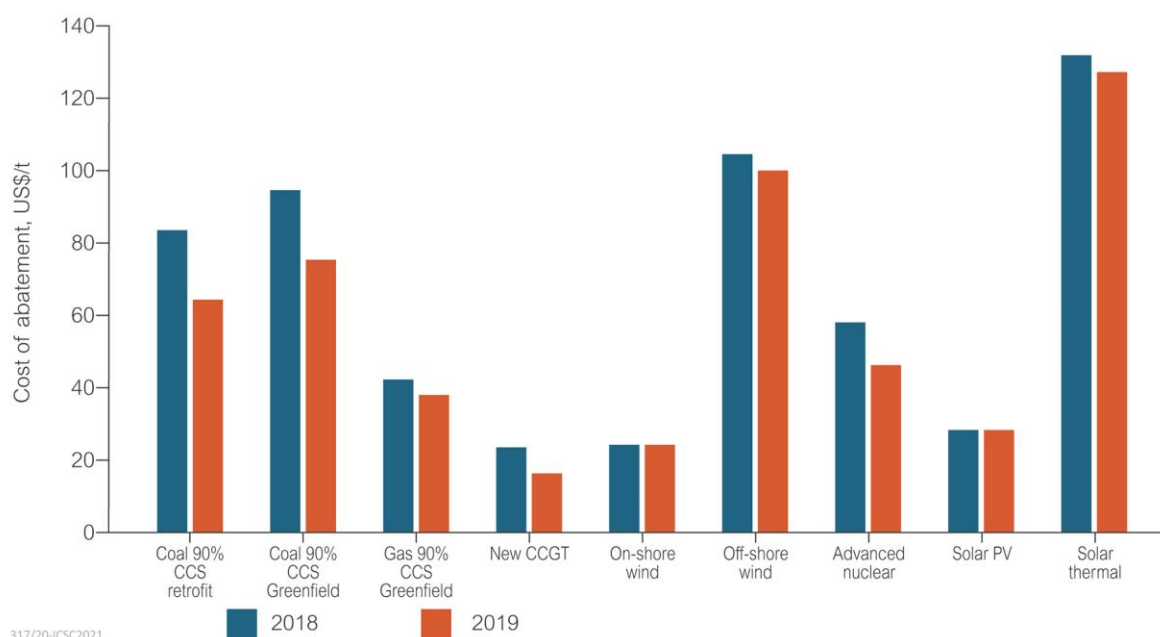
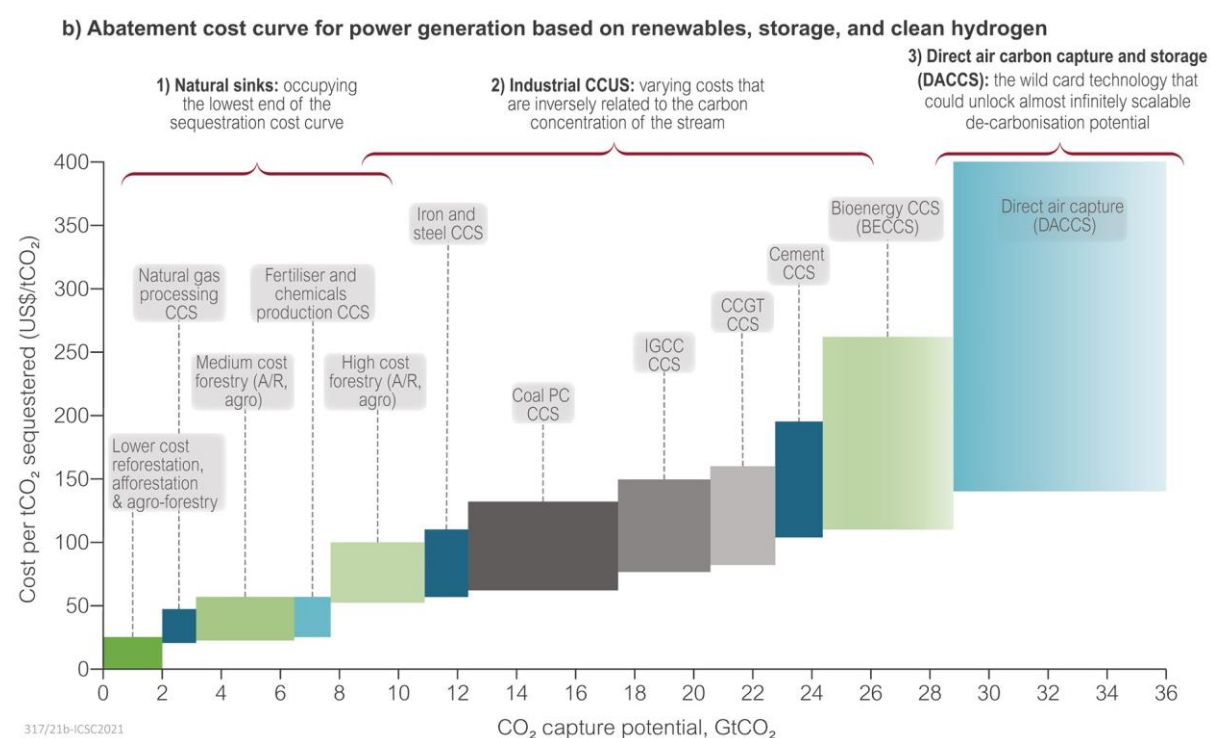
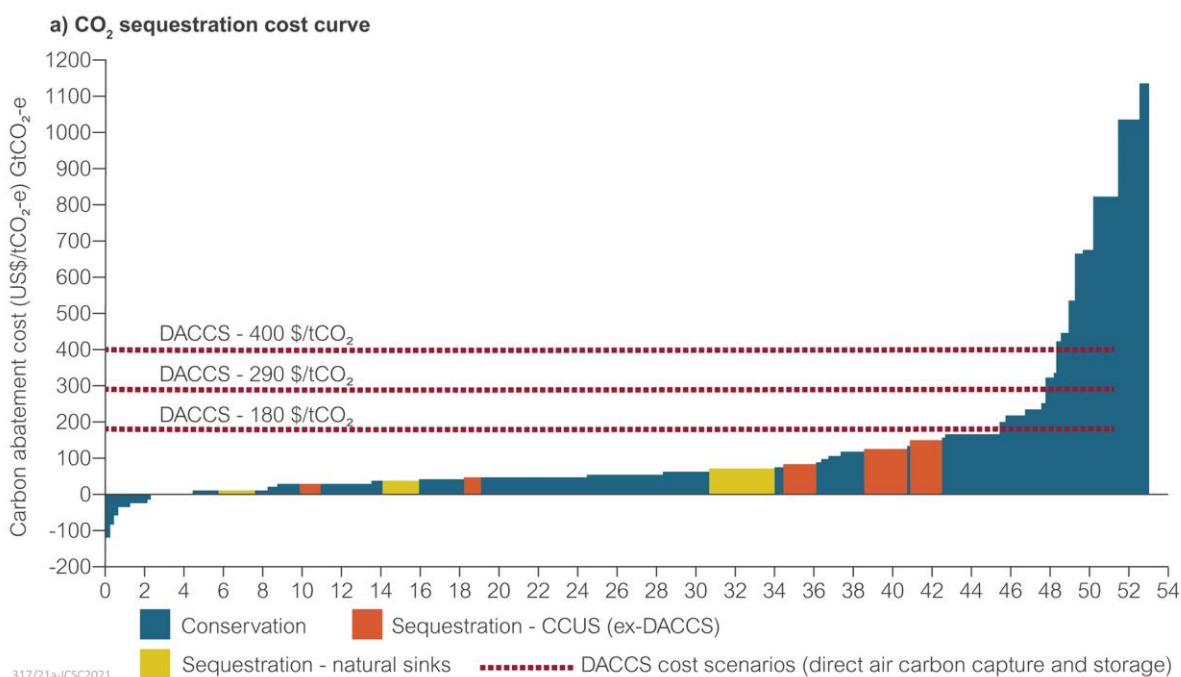


Figure 20 Abatement costs for different generating technologies in the USA relative to existing coal-fired plant (adapted from Gillingham and Stock, 2018)

Figure 20 shows the 2018 results together with updated values obtained from the 2019 Annual Energy Outlook (see Section 4.1.3) using the same method. It can be seen that the costs of all sources have fallen since 2018, but coal-CCS has seen the largest relative and absolute cost reduction. Despite this, coal-CCS is a higher cost form of CO₂ abatement compared to all sources other than offshore wind or solar thermal. Owing to the consistent assumption that coal emissions are displaced, gas-CCS performs much better than it does in the CO₂ avoided analyses presented in Section 4.2.2, where it is generally compared against an unabated gas plant.

A popular means of expressing CO₂ abatement costs (and those of greenhouse gases more broadly) is in the form of an abatement cost curve, which places each tonne of CO₂ emitted in order of the cost of its elimination (McKinsey, 2009). This can be applied across the whole global economy, or for specific sectors or regions. The cost curves developed by Goldman Sachs for the 2020 edition of its ‘Carbonomics’ report, covering all anthropogenic greenhouse gas emissions, are noteworthy for representing both ‘carbon conservation’ and ‘carbon sequestration’ routes in parallel (Della Vigna and others, 2020). Carbon conservation refers to mitigation of greenhouse gas emissions through renewables deployment, switching to low-carbon fuels, and energy efficiency improvements, while sequestration includes afforestation and CCS applied to industry, power, biomass and direct air capture. Figure 21a) shows the ‘merged’ conservation and sequestration cost curves, in which the lowest cost mitigation option is chosen for each emissions source. This combined solution provides a lower overall cost than the abatement curve without sequestration, indicating that over 60% of total emissions can be abated at a carbon price of less than 100 \$/t. The study also postulates that the availability of geological sequestration of CO₂ captured from the atmosphere, known as direct air capture and storage

(DACCS) would set an upper cost limit on a range of emissions for which there is currently no (or a very costly) abatement option.



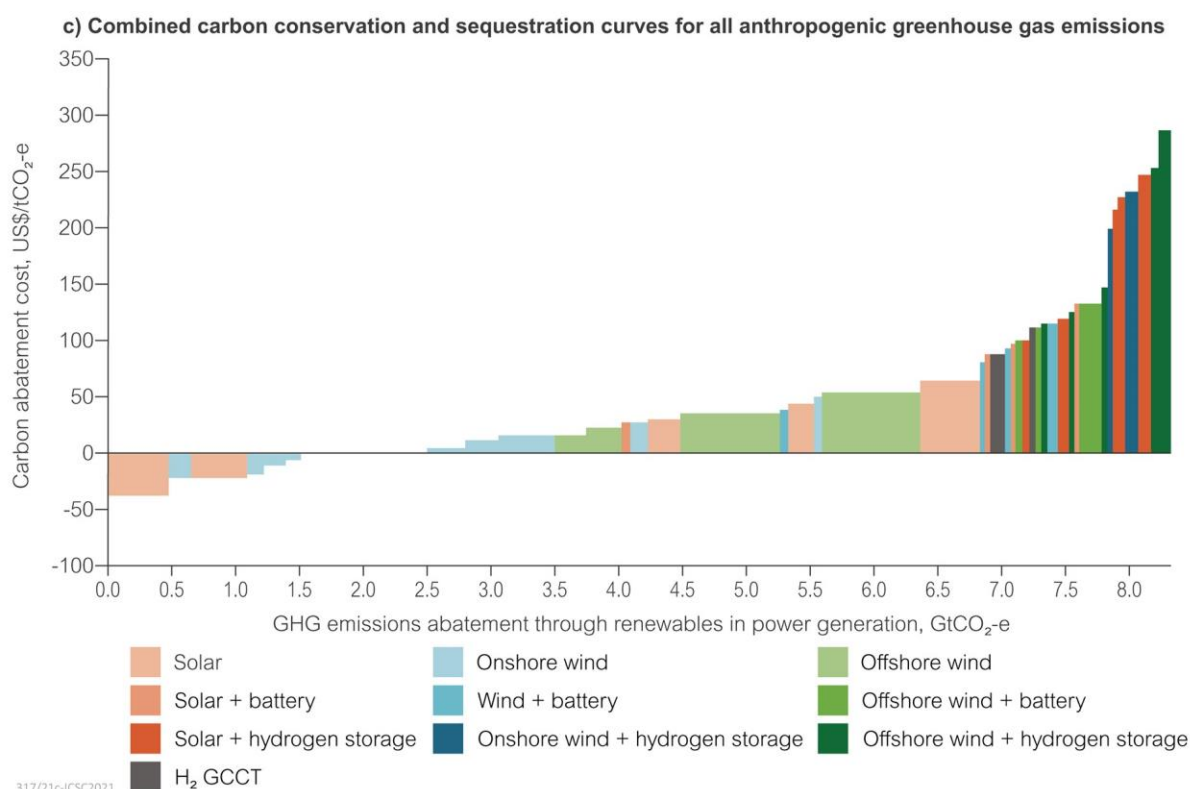


Figure 21 Cost curves for CO₂ sequestration and abatement (Della Vigna and others, 2020)

The sequestration costs for CCS are gathered from the GCCSI, although no further details of the source data are provided. In comparison with the conservation curve, the sequestration cost curve (Figure 21b) is characterised by greater cost uncertainty but more potential for lower cost abatement at the high-cost end of the curve (the so-called ‘hard-to-abate’ emissions). These estimated sequestration costs can be compared with the conservation curve costs for power generation shown in Figure 21c. With a cost range of 60–130 \$/t, coal-CCS would come at the higher end of solar PV costs, and below most combinations of VRE sources paired with storage (which attempt to approximate a dispatchable power source). However, it is not clear whether these sequestration costs represent CO₂ avoided costs, taking into account the need to replace power lost to the CCS energy penalty, or if they simply indicate the cost of capture and storage retrofit for each emissions source. Equally, it is not indicated how abatement costs and sequestration costs have been merged for the combined cost curve or in which sectors sequestration has been deployed in this lowest-cost pathway.

In China, a comparison of CCS retrofit costs with onshore wind costs is provided by Singh and others (2019). Costs for wind power are based on Liu and others (2015), which estimated a specific capital cost of 677 \$/kWh in 2020 and capacity factors of 0.17 to 0.26. Assuming that wind power can reliably replace 25% of coal generation, a combined cost curve for wind and coal-CCS is produced based on capital costs only. The highly intermixed nature of abatement costs for wind and CCS retrofits suggests this mixed deployment strategy offers the most cost-effective decarbonisation strategy.

4.2.4 Summary

- The cost of CO₂ capture for operating and proposed coal-CCS plants is falling and is expected to be around 45 \$/t for the next generation of retrofit projects.
- Cost reductions are associated with learning-by-doing, economies of scale and modular construction, improved financing, and technology optimisation.
- The cost of CO₂ avoided provides a more useful measure of emissions abatement potential, and generally falls in the range of 60–80 \$/t for new coal-CCS plant in high-income countries.
- The cost of CO₂ avoided for coal-CCS in China could be as low as 30 \$/t for favourable retrofit options.
- Accurate comparison of CO₂ abatement costs with other low-carbon generation is challenging and highly dependent on the reference scenario.

4.3 TOTAL SYSTEM COST ANALYSIS

A select number of studies have investigated the role of CCS-equipped power plants in lowering the total system cost of a decarbonised electricity grid, particularly in the context of achieving a net zero emissions grid by 2050. As outlined in Section 3.2, these analyses use complex models to simulate real grid dispatch at each level of decarbonisation, and include constraints to ensure the grid has sufficient dispatchable capacity, flexible reserve capacity, and inertia to maintain grid frequency.

In general, the lowest-cost energy mix for a net zero grid includes some proportion of dispatchable, low-carbon capacity such as nuclear or CCS-equipped power plant. However, the low flexibility and high capital cost of nuclear plant means that new nuclear features relatively little in high renewables scenarios, as it is not technically or economically suited to very low operating hours. On the other hand, CCS can provide flexible generation via two routes: unabated fossil fuel plant offset by negative emissions from biomass-fired CCS plant (bioenergy CCS, BECCS); or fossil fuel plant equipped with CCS. At net zero, it should be noted that the latter case also requires some BECCS to offset any residual, uncaptured emissions. BECCS therefore plays a key role in most analyses of net zero emissions, and the proportion of unabated and CCS-equipped fossil fuel plant will depend largely on fuel costs (biomass, coal, and gas) and the distribution of existing generating assets.

Energy storage is another option for providing grid services such as dispatchable capacity during periods of low renewable generation. However, while battery storage can be useful for balancing daily fluctuations (particularly shifting solar power generation beyond sunset), it is not cost effective at providing sufficient capacity to cover long periods with little generation, such as calm winter days (Bongers and others, 2021). Longer-term, high-capacity storage is considered by some studies, including pumped hydropower, which is limited by the number of geographically suitable locations, or power-to-gas, which is a relatively costly option. Fundamentally, a combination of renewables and energy storage typically requires very high total generating capacity, to ensure sufficient generation

during favourable weather conditions to not only meet demand but also charge storage for future periods of low generation. So, despite low unit costs for VRE, total system costs for solutions without coal, gas, or nuclear plant tend to be relatively high.

A 2019 study for the IEA Coal Industry Advisory Board used the Electricity System Optimisation (ESO) tool to model six different regional electricity grids in a transition to net zero in 2050, including the UK, Poland, New South Wales (Australia), Jamali (Indonesia), ERCOT (Texas), and PACE (a Mid-western US grid) (Pratama and Mac Dowell, 2019). Costs for CCS deployment on coal, gas, and biomass plants are taken from the study conducted for the UK Government discussed in Section 4.1.1. In all cases, coal- and/or gas-fired power plants with CCS featured in the lowest-cost pathway, and eliminating CCS from the model led to significant increases in the total cost of the transition – by up to 350% in the case of the Indonesian grid (Figure 22). This study also looked at the effect of restricting the grid to renewable energy and battery storage technologies only, which generally yielded similar energy mixes and costs to the cases forbidding CCS only.

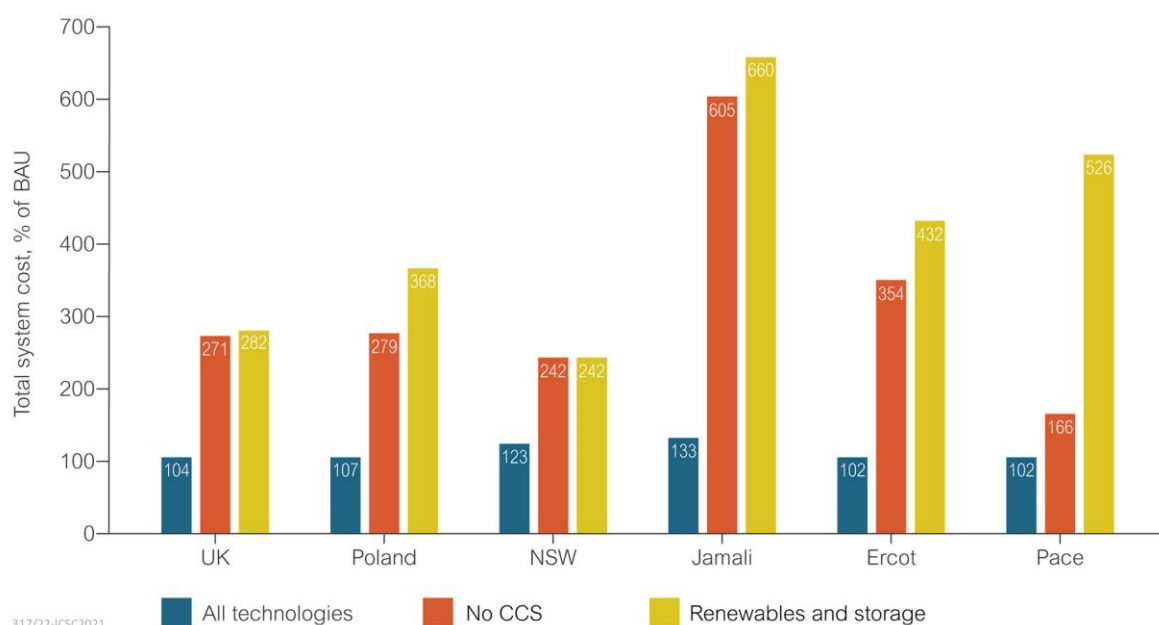


Figure 22 The effect of removing CCS from net zero scenarios for a range of electricity grids (Pratama and Mac Dowell, 2019)

The net zero grid compositions with all technologies available tend to employ coal-CCS plant in a baseload role, with gas-CCS plant used for load following in response to varying demand and VRE output.

A similar study conducted by the same authors for the ICSC looked at grid decarbonisation in South Korea, Germany, and Vietnam, in addition to re-analysing Poland and Indonesia's Jamali grid in more detail (Pratama and Mac Dowell, 2021, in draft). This work introduces the option of long-term, seasonal energy storage in the form of power-to-gas technology (in addition to lithium-ion batteries for short-term storage). A constraint on build rates is also implemented, which only permits the build rate for a given technology to double every five years – this is in keeping with past deployment rates

achieved by an advanced economy such as Germany. In ‘no-CCS’ scenarios, this constraint has the effect of limiting the electricity supply growth of the high-growth economies (Vietnam, Indonesia, and to a lesser extent, Poland), as it becomes impossible to meet projected growth using renewables and energy storage alone. Based on the energy intensity of GDP, this lost growth can be quantified as a cost to the economy, amounting to over to \$49 trillion in the case of Vietnam in 2050. This compares with a total system cost range of \$200–1000 billion in scenarios where CCS is permitted (see Figure 23).

On the other hand, the established high build rates for renewables in Germany allow net zero to be achieved through a massive increase in solar and wind capacity. Although the ‘all technologies’ scenario sees only small amounts of CCS capacity (largely CCGT-CCS and BECCS) built to complement this VRE capacity, without the option of CCS, total costs over the 30-year period are over 2.5 times higher. In South Korea, CCGT-CCS also features heavily in the lowest-cost scenario, comprising over a third of total generation by 2050. Unlike Germany, which requires nuclear phase out by 2025, South Korea has only ruled out new nuclear, and significant nuclear capacity remains in 2050 to complement VRE in the ‘renewables only’ scenario.

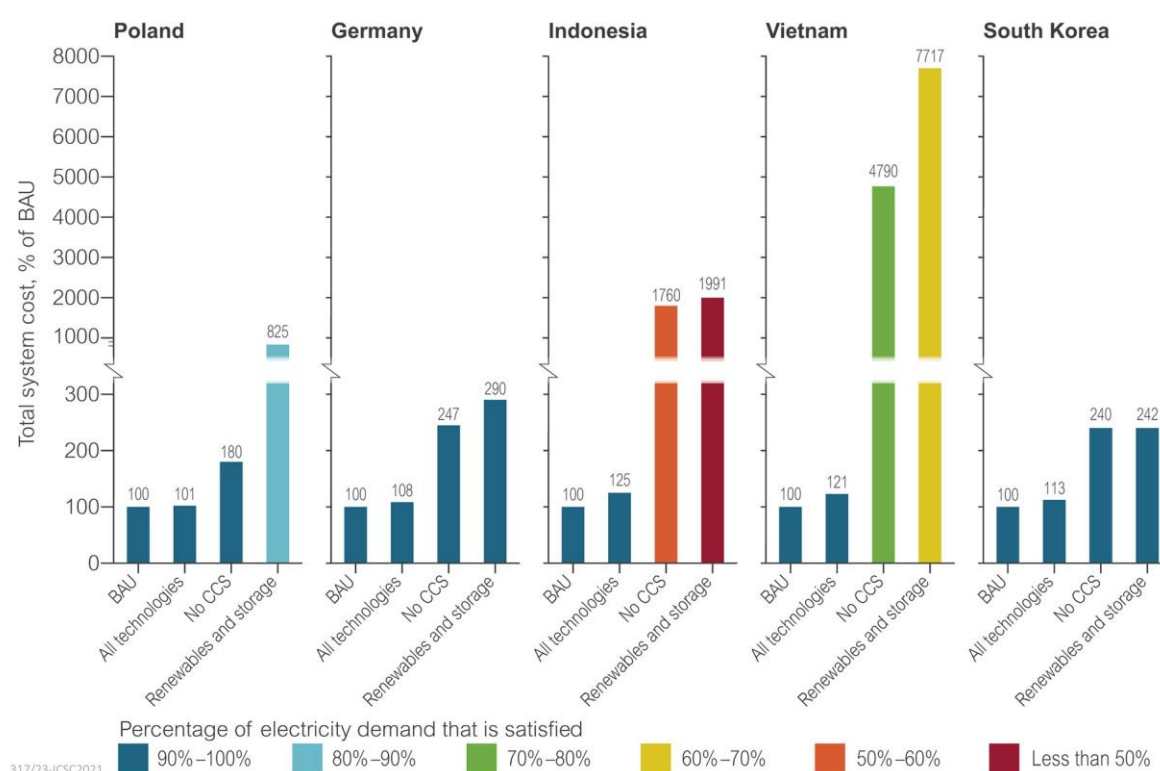


Figure 23 Total system costs for various regions and scenarios to 2050 (Pratama and Mac Dowell, 2021 in draft)

This study also examines the effect of variables such as CCS capital cost, efficiency, capture rate, and fuel costs, running separate scenarios with all combinations of these factors. Increasing the capture rate from 90% (base case) to 98% is shown to have a particularly significant effect on the relative deployment of coal and gas-CCS at net zero, as the high residual emissions from coal-CCS at 90% capture can become costly to offset.

Figure 24 shows the distribution of costs generated by the different combinations of variables for various levels of decarbonisation in Germany. By also showing scenarios in which CCS deployment is forbidden, it is apparent that a sharp increase in total system cost is incurred as net zero is approached.

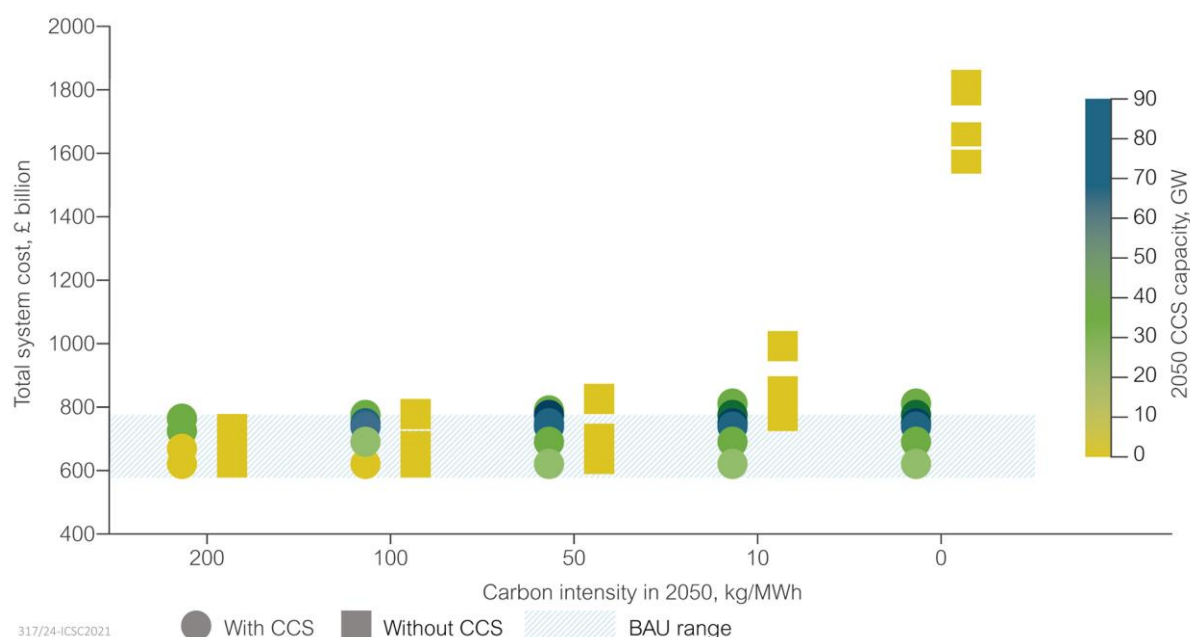


Figure 24 Increase in total system cost in Germany, with and without availability of CCS (Pratama and Mac Dowell, 2021 in draft)

Using a similar grid optimisation and deployment model known as Modelling Energy and Grid Services (MEGS), Gamma Energy Technology and Red Vector have conducted several analyses of the total system cost of decarbonising Australia's National Energy Market (NEM) grid (Boston and others, 2018; Bongers and others, 2021; Boston and Bongers, 2021). This long, interconnected region covers the entire eastern side of the country from Tasmania and South Australia to Northern Queensland.

Both studies of the NEM highlight the 'incremental cost of abatement' when decarbonising the grid with a given low-carbon technology. This describes the increase in total system cost for each additional tonne of CO₂ abated. The work highlights that VRE sources provide the lowest-cost abatement option, followed by coal-to-gas switching. However, both these options start to see an exponential increase in the incremental cost of abatement at around 50–60% decarbonisation, at which point coal or gas plant with CCS provides the lowest-cost option (Figure 25).

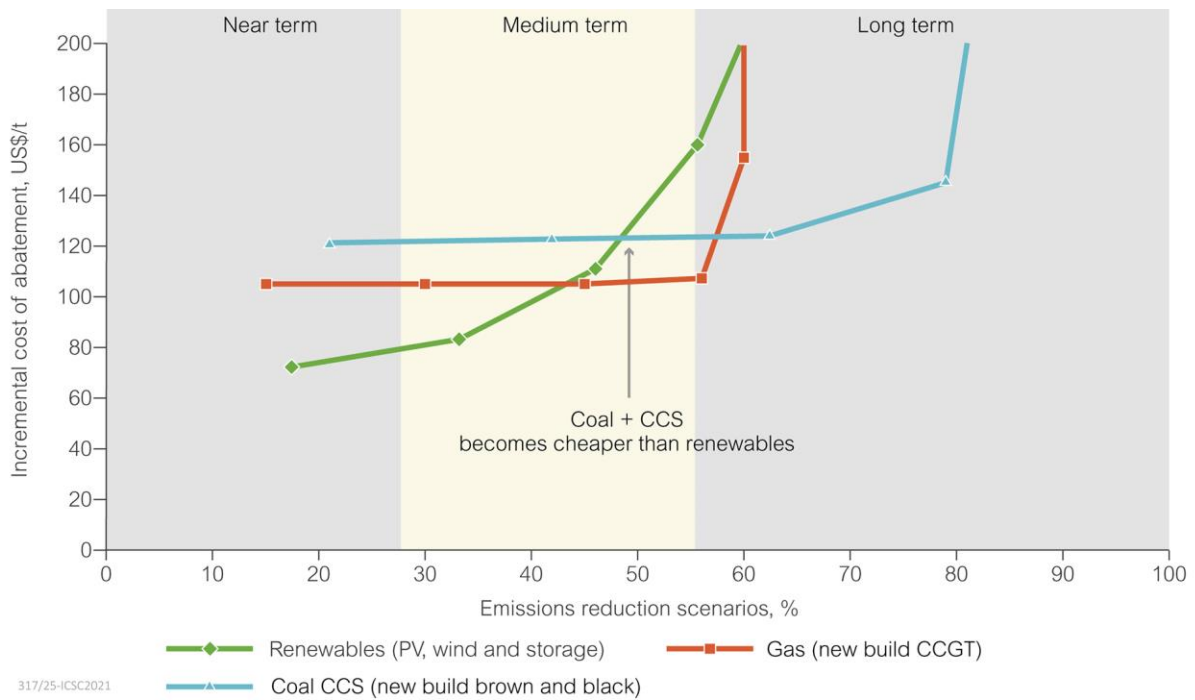


Figure 25 Incremental CO₂ abatement costs for Australia's NEM using individual technologies (Boston and others, 2018)

The 2021 study of the NEM includes a statistical analysis known as S-MEGS, in which over 3000 scenarios with randomly generated energy mixes are costed and sorted according to the level of decarbonisation they achieve (Figure 26) (Bongers and others, 2021). With all technologies permitted, the optimal total system cost at 100% decarbonisation in 2050 is over 110 AUS\$/MWh (80 \$/MWh), or AUS\$30 billion per year (\$22 billion per year). Fossil fuel-based CCS and BECCS are a relatively low proportion of total capacity (<10% combined), but a much higher proportion of total generation, at 14% for fossil fuel-CCS plant and 10% for BECCS. By identifying the scenarios generated without CCS (including both fossil fuel and biomass-fired plants), a lowest cost pathway or 'frontier' with this constraint can be established, as highlighted in Figure 26. This pathway deviates from the 'all available technologies' lowest-cost pathway at around 85% decarbonisation, at which point fuel switching from coal to gas is no longer adequate and significant additional VRE capacity is required, as well as nuclear power for dispatchable generation. Without CCS, the total system cost increases exponentially as net zero is approached, owing largely to a massive increase in installed capacity: over 230 GW of capacity is needed at 99.5% decarbonisation, relative to around 160 GW in the unconstrained lowest cost pathway.

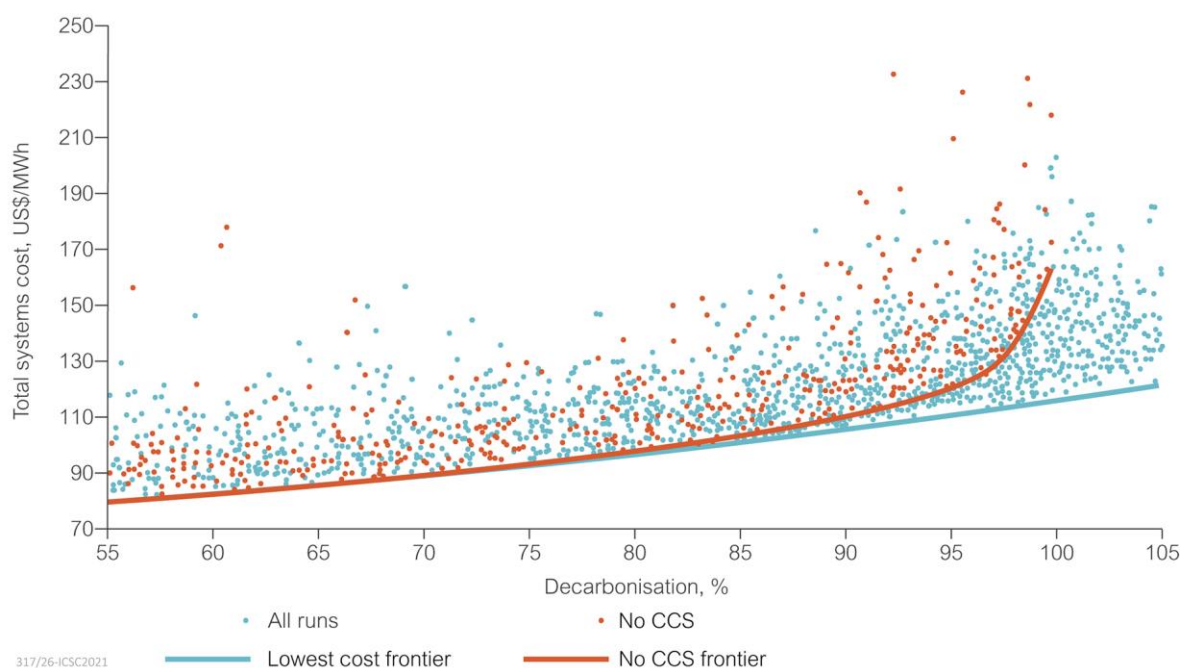


Figure 26 The total system cost of over 3000 different energy mix scenarios, with scenarios without CCS highlighted (Bongers and others, 2021)

The analysis also finds that unabated coal plant tends to feature in lowest-cost net zero scenarios as, thanks to low fuel costs and Australia’s sizeable fleet of amortised coal plants, it provides the lowest-cost option for emergency peaking plants, when offset by BECCS plant. These plants would run at very low load factors, sometimes generating for only a few days in winter; in practice, they may not find sufficient value in the market to justify any necessary upgrades or increased maintenance associated with such an operating regime. Eliminating coal early on is found to incur a total system cost penalty of AUS\$2 billion per year (\$1.46 billion per year).

Gamma Energy Technology have also introduced the metric ‘SCoRE’, described in Section 3.2, which aims to place a \$/MWh value on each new unit of a given low-carbon generating capacity (Gamma Energy Technology, 2019). The SCoRE for each technology will vary as the underlying grid composition varies, and an ‘ideal mix’ of new capacity can be identified as the combination of new capacity which yields the lowest SCoRE. SCoREs for Australia’s NEM at various levels of decarbonisation are shown in Table 2, highlighting that CCS-equipped generation is costly at early stages of decarbonisation but very competitive at higher levels of mitigation (75%).

TABLE 2 SYSTEM COST OF REPLACEMENT ENERGY (IN AU\$/MWH) FOR DIFFERENT ENERGY SOURCES IN AUSTRALIA'S NEM (GAMMA ENERGY TECHNOLOGY, 2019)					
Decarbonisation target	<10%	25%	50%	75%	>90%
SC coal	48	–	–	–	–
CCGT	47	48	54	–	–
Coal CCS	112	112	113	119	–
BECCS	247	247	248	248	249
Nuclear	199	199	200	205	242
Wind	58	68	232	–	–
Utility PV	84	120	–	–	–
Renewables and storage	58	68	108	448	–
Ideal mix	48	58	84	106	110

4.3.1 Summary

- Total system cost analysis offers the most comprehensive assessment of the costs to society of grid decarbonisation and the factors which can influence those costs.
- Wind and solar power offer the lowest-cost option for the initial stages of decarbonisation, and see very high levels of deployment at net zero emissions for all grids studied.
- However, low-carbon dispatchable generation becomes extremely valuable as high levels of decarbonisation (>80–90%) are approached.
- Various forms of CCS frequently offer the most economic option for this dispatchable generation, with the proportions of coal, gas, or biomass dependent on local factors.
- Realistic constraints on the rate of renewables deployment in emerging economies suggest that CCS-based power plants may play a much greater role in the lowest-cost pathway to net zero emissions.

5 CONCLUSIONS

Despite the considerable variation in assumptions and methodologies adopted by the cost estimates reviewed in this report, there is broad agreement that CCS-equipped power plants are currently a relatively costly option for CO₂ abatement on a cost of electricity basis. Following over a decade of falling costs for solar power, onshore wind and, more recently, offshore wind, in most regions these technologies are unparalleled as low-cost, low-carbon generation. However, it is vital to recognise that these variable renewable energy (VRE) sources were once also characterised by high costs of electricity – on the order of those estimated for new CCS power plants today. The dramatic improvement in economic performance has been brought about by a range of supportive policies in several jurisdictions, such as subsidised wholesale electricity tariffs and production tax credits, which have allowed the wind and solar industry to harness economies of mass production, access low-cost project financing, and accelerate progress on the learning curve of technology optimisation. On the evidence of cost reductions already achieved by current CCS projects in the power sector, it is very likely that the leading capture technologies (such as amine-based solvents) can undergo a similar improvement, if mechanisms are put in place to ensure deployment at scale.

However, do electricity grids need another source of low-carbon generation when wind and solar power have been so effectively nurtured to a highly cost-optimised position? While these sources will undoubtedly feature heavily in most decarbonised grids (particularly where large-scale hydropower is not available), complete decarbonisation of an electricity grid is a complex challenge which defies the use of simplistic cost metrics. Developed societies demand a high level of grid reliability, in which electricity supply is able to consistently meet consumer demand at all times and across all seasons. Ensuring this level of reliability is particularly challenging for emerging economies with rapid demand growth; the importance of this need is underlined by the UN's 7th Sustainable Development Goal to 'ensure access to affordable reliable, sustainable and modern energy for all'. The intermittent nature of VRE sources introduces a new level of complexity to grid planning, and regions with high levels of wind and solar deployment, such as California, South Australia, and Texas, have already begun to experience some early challenges with maintaining reliable supply.

This report has highlighted how broadening cost analysis to the level of the entire grid system is an increasingly useful approach when assessing the value which different generation technologies can bring to decarbonisation. Using grid dispatch models with high temporal resolution and realistic weather data, this analysis can ensure that a given energy mix is able to supply electricity supply at the required level of reliability. By also incorporating the deployment of new, low-carbon capacity with the constraint of minimising system cost, the optimum pathway to net zero can then be identified. As higher levels of decarbonisation are approached, intermittent generation delivers diminishing returns, as more and more installed capacity is required to deliver each tonne of CO₂ abatement while simultaneously ensuring reliable supply. Energy storage technologies can play an important role in

redistributing renewable supply, but grid models clearly elucidate the limits of this approach, which still rely on disproportionately high levels of renewable capacity.

Enabling the deployment of CCS-equipped power plants – even at today’s cost levels – is demonstrated to unlock significant reductions in the total cost of decarbonising to net zero. For developed countries with well-established supply chains for VRE technologies and good wind or solar resources, this saving can be of the order of 50–80%. In such cases, a relatively small proportion of CCS capacity plays a disproportionately large role in providing back-up generation to a large VRE fleet; CCS-equipped generation may be further limited where existing nuclear capacity can also contribute to this role. Despite the cost advantage identified for CCGT-CCS over coal-CCS for most regions on an LCOE basis (excluding China and some other Asian economies), these two options are deployed in a much more mixed fashion for most grids studied at the system level, with low-cost coal supply and large existing coal fleets favouring extensive coal-CCS retrofits in particular. In emerging economies, the role of CCS-equipped power plants is even greater, providing not only grid reliability but another vital route to satisfying low-carbon demand growth where VRE supply chains are unable to keep up. The benefits of preventing any slowdown in the economic growth of these regions are significant and far-reaching, encompassing not only savings of trillions of dollars of lost growth, but the associated improvements in the health and well-being of their populations.

In practice, electricity system planning at the policy level already goes well beyond a simplistic LCOE analysis, making use of detailed demand projection scenarios and grid modelling. However, cost of electricity metrics are still of great relevance to the energy transition, in that they appear to heavily influence the perception of different generating technologies in both public and policy circles. In addition, for a high-level system plan to net zero emissions to be delivered in practice, investors in new capacity must have a real financial incentive to deliver the optimum generation mix. Translating the system value of each technology in a decarbonised grid into appropriate incentives – either through electricity markets or other policy instruments – is therefore the central challenge for policymakers.

Some new cost of electricity metrics, such as LACE and VALCOE have attempted to illustrate better the real market value of different forms of generation, quantifying the opportunity which an investor in dispatchable power may gain from, for instance, recouping high electricity prices at times of scarce renewable supply, or gaining firm capacity contracts. However, the dependence of these metrics on the nature of the current energy mix also highlights the temporal challenge of a rapid move to net zero – what is valuable to the grid today may change tomorrow, and it is difficult to capture such an evolving situation with market signals alone. Here, there must undoubtedly be a role for more far-sighted policy, which can express the value discovered by a whole system analysis and help steer the grid towards an optimum cost solution. It is not sufficient to only meet the demands of a 90% decarbonised grid when this milestone is reached; the technologies needed to meet those demands – including CCS – must be in place to fulfil this role well in advance, particularly given the further cost reductions which can be

harnessed through greater deployment. It is therefore essential that total system cost analysis gains greater prominence in the public and policy debate surrounding grid decarbonisation. This will be assisted by the development of new, more accessible means of communicating system costs, which will be necessary to challenge the dominance that LCOE has enjoyed over the past decades.

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