Department for
Business, Energy
& Industrial Strategy

Hydrogen Production Costs 2021

August 2021

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Contents

Acronym Glossary

Name	Acronym
Air Separation Unit	ASU
Auto-Thermal Reformer	ATR
Bio-Energy with Carbon Capture and Storage	BECCS
Capital expenditure	CAPEX
Carbon Capture, Usage and Storage	CCUS
Carbon Dioxide	CO2
CO2 Transmission and Storage	CO2 T&S
Gas Heated Reformer	GHR
Higher Heating Value	HHV
Hydrogen	H2
Levelised cost of hydrogen	LCOH
Load Factor	LF
Long run variable cost	LRVC
Lower Heating Value	LHV
Megawatt	MW
Megawatt electric	MWe
Megawatt-hour	MWh
Megapascal	MPa
Operating expenditure	OPEX
Proton Exchange Membrane	PEM
Solid Oxide Electrolysis	SOE
Steam Methane Reformation	SMR

Introduction

Low carbon hydrogen will be vital for meeting our legally binding commitment to achieving net zero by 2050, with potential to help decarbonise vital UK industry sectors and provide flexible energy across heat, power and transport.

Hydrogen production costs are a fundamental part of energy market analysis, and a good understanding of these costs is important when analysing and designing policy to make progress towards net zero.

This report, produced by the Department for Business, Energy and Industrial Strategy (BEIS), presents estimates of the costs and technical specifications for different production technologies. The report does not cover the costs of hydrogen compression, storage, transmission, distribution or end use.

This is the first report by BEIS setting out the levelised cost of hydrogen production technologies (LCOH). It is based on previously published underlying technology cost information prepared by Element Energy for BEIS in 2018[1]. **We acknowledge that the evidence base is fast-moving and that there are gaps in our knowledge. We are therefore inviting views on this report and the data published alongside it to continue to improve our evidence base.** To provide your views and any new evidence, please email HydrogenEvidenceBase@beis.gov.uk. We will continue to monitor and update cost estimates based on new evidence as it becomes available.

In this report we consider the costs of construction and operation, reflecting the cost of building and operating a generic production plant for each technology. Potential revenue streams are not considered. The majority of costs in this report are presented as levelised costs, which is a measure of the average cost per MWh of hydrogen produced over the full lifetime of a plant. All estimates are in 2020 real values.

Levelised costs provide a straightforward way of consistently comparing the costs of different production technologies with different characteristics, focusing on the costs incurred by the producer over the lifetime of the plant. However, the simplicity of the measure means that there are factors which are not considered, including a technology's impact on the wider system, which is particularly important for a cross-cutting energy vector like hydrogen.

BEIS considers these impacts through its wider modelling. The production costs underlying the straightforward levelised cost metric are used as inputs to BEIS analysis, including energy system modelling and more specific policy analysis, such as for hydrogen business models or the Net Zero Hydrogen Fund. However, it is important to note that levelised costs do not indicate costs that will be taken into account or used in determining payments under future business models. For further details, please see Section 2.

[1] Element Energy (2018), 'Hydrogen supply chain evidence base' (viewed on 18 June 2021).

This report is structured as follows:

• Section 1 gives a summary of different hydrogen metrics and which ones are used by BEIS.

• Section 2 provides an overview of how levelised costs are calculated and what is and is not included in them.

• Section 3 outlines how BEIS uses production cost data in its modelling.

• Section 4 provides a short description of the different technology types we are considering in this report.

• Section 5 presents the underlying assumptions for the levelised cost estimates presented in Section 6 and 7.

• Section 6 presents the levelised cost estimates for the core set of hydrogen production technologies.

• Section 7 presents sensitivity analysis showing the impact of various uncertainties on the levelised costs presented in Section 6.

• The annex, published alongside this report, presents the underlying technology cost and technical detail and the estimated levelised costs for the full range of technologies and sensitivities for 2020, 2025, 2030, 2035, 2040, 2045 and 2050 (unless stated otherwise) covered in this report.

Uncertainty

As with any projection, there is inherent uncertainty when estimating current and future costs of hydrogen production, particularly given that certain technologies do not yet exist at scale or have not yet been demonstrated. While we consider that the ranges of levelised cost estimates presented in this report are robust for BEIS analysis, these estimates should also be used with a level of care given the uncertainties around the future cost of production. These uncertainties include the potential for unanticipated or further cost reductions in less mature technologies, greater uncertainty for technologies where we have access to less detailed evidence, and uncertainty around electricity and fossil fuel prices. To illustrate the potential effects of these uncertainties, the report presents ranges and sensitivity analysis on the effects of changes in parameters.

Covid-19

The analysis in this report is predominantly based on technology cost information gathered in 2018. Electricity and fuel prices are based on published BEIS data, derived before the Covid-19 pandemic. Therefore, the pandemic's impact on production costs is not considered in this report.

Section 1: Hydrogen metrics

There are a variety of different ways to talk about hydrogen capacities, production quantities and costs. As hydrogen will be used as energy input in end-use sectors, the standard definition used by BEIS refers to capacity and quantities in terms of energy units: MW and MWh, respectively. We are using the higher heating value (HHV[2]) to express MWh. Table 1.1 provides a table with common hydrogen metrics. In this report, when quoting MW or MWh, they refer to MW H2 (HHV) and MWh H2 (HHV), unless otherwise stated. The levelised costs of hydrogen (LCOH), defined in Section 2, are expressed as costs per MWh H2 (HHV) in this report.

Table 1.1: Hydrogen metrics

Plant size / Capacity	
MW H2 (HHV)	MWe (electrolysers only)*
1	$1MW\ H2\ (HHV) * \frac{MWh\ electric\ input}{MWh\ hydrogen\ (HHV) output}$

* Not used in this report, quoted for reference only.

Turning capacity into energy output	
MW H2 (HHV)	MWh H2 (HHV)
1	$1MW\ H2\ (HHV) * 24h * 365\ days * load\ factor\ (\%)$

Production / Output			
MWh H2 (HHV)	MWh H2 (LHV)	kg H2	Nm³ H2
1	0.85	25.4	282

Common levelised cost metrics		
£/MWh H2 (HHV)	£/MWh H2 (LHV)	£/kg H2
1	1.18	0.03937

[2] HHV refers to the total amount of heat liberated during the combustion of a unit of fuel, including the latent heat stored in the vapourised water. Lower heating value (LHV) refers to the total amount of heat available from a fuel after the latent heat of vaporisation is deducted from the HHV.

Section 2: How levelised costs are calculated

The levelised cost of hydrogen (LCOH) is the discounted lifetime cost of building and operating a production asset, expressed as a cost per energy unit of hydrogen produced (£/MWh). It covers all relevant costs faced by the producer, including capital, operating, fuel and financing costs.

The levelised cost of a hydrogen production technology is the ratio of the total costs of a generic/illustrative plant to the total amount of hydrogen expected to be produced over the plant's lifetime. Both are expressed in net present value terms. This means that future costs and outputs are discounted, when compared to costs and outputs today. Technologies' financing cost (also referred to as the weighted cost of capital (WACC) or hurdle rate in this report) is applied as the discount rate (see Section 5 for further detail). This means it is not possible to express financing cost as a £/MWh component of the cost directly.

Levelised cost estimates do not consider revenue streams available to producers (for example from sale of hydrogen).

The main intention of a levelised cost metric is to provide a simple "rule of thumb" comparison between different types of hydrogen production technologies. However, the simplicity of this metric means some relevant issues are not considered. Further details on the considerations included and excluded from levelised costs can be found in Section 3.

Table 2.1 demonstrates at a high level how LCOH are calculated and what is included. Further detail on what is included within the plant boundary and which assumptions underpin the components set out below can be found in Section 5. Importantly, LCOH is a production cost metric and does not include any costs associated with delivery or storage of the produced hydrogen, nor costs of end-use adaptation. These costs could be substantial. Future work should consider the potential charges producers may face for using a hydrogen distribution, transmission and storage network.

Note, that currently we only have limited evidence on the level and timing of pre-development and decommissioning costs. We are inviting stakeholders to share any evidence they may hold.

Whilst our evidence base includes capital and operating costs for compressing hydrogen, we have not included these costs in our LCOH, as they depend on the type of network (transmission or distribution) a plant connects to or whether it requires storage (see further detail in Section 5). Future work will explore this further.

Table 2.1: Steps to calculate levelised costs

Step 1: Gather plant data and assumptions		
Capital Expenditure (CAPEX): • Construction and equipment costs*	**Operating Expenditure (OPEX):** • Fixed OPEX* • Variable OPEX* • CO2 transport and storage cost • Fuel and electricity costs • Carbon costs	**Expected Production Data:** • Capacity of plant • Expected load factor • Expected efficiency*

* Adjusted over time for learning.

Step 2: Sum the net present value of total expected costs for each year
$NPV\ of\ Total\ Costs = \sum_n \frac{Total\ CAPEX\ and\ OPEX_n}{(1 + discount\ rate)^n} \qquad n = time\ period$

Step 3: Sum the net present value of expected production for each year
$NPV\ of\ Hydrogen\ Production = \sum_n \frac{Hydrogen\ Production_n}{(1 + discount\ rate)^n} \qquad n = time\ period$

Step 4: Divide total costs by net production
$Levelised\ Cost\ of\ Hydrogen = \frac{NPV\ of\ Total\ Costs}{NPV\ of\ Hydrogen\ Production}$

Levelised cost estimates can be reported for different milestones associated with a project including the project start, the financial close and the online/commissioning year. In this publication, we report levelised cost estimates by online/commissioning year. As the evidence currently assumes a uniform build time of three years across technologies and excludes pre-development timings (due to lack of evidence), assuming project start of financial close would not introduce differences between technologies. In reality there is likely to be variation in pre-development and construction timings across technologies and we are inviting stakeholder views.

Section 3: How BEIS uses production cost data in modelling and policy making

Use in modelling and policy analysis

The estimates outlined in this report are intended to provide a high-level, static view on the costs of different hydrogen production technologies for generic/illustrative rather than site-specific projects[3]. Because levelised costs are a simplified metric, focusing only on those costs accruing to the owner/operator of the production asset, the metric does not cover wider impacts to the energy system, such as need for networks and storage or wider flexibility benefits for use across sectors. These are considered in dynamic system models instead.

In practice, BEIS's energy system modelling and more specific policy analysis does not use levelised cost estimates directly. Instead, it optimises system costs (or in the case of specific policy analysis estimates policy impacts) using the underlying capital expenditure (CAPEX) and operating expenditure (OPEX) assumptions incorporated in the levelised cost estimates shown in this report.

Levelised Costs are not "Strike Prices"

The levelised cost estimates in this report do not provide, nor should be seen as, an indication of potential strike prices[4] under a future hydrogen business model.

For example, in the power sector, generation cost assumptions (along the lines of hydrogen production cost assumptions in this report) are only one set of inputs into setting administrative strike prices – the maximum strike price applicable to a technology in a Contracts for Difference (CfD) allocation round. Strike prices include additional considerations, such as market conditions, revenues for generators, and policy factors, which are not considered in levelised costs. In addition, generic average cost information may be different from that used as part of the administrative strike price-setting process.

[3] This also means that land costs are not included.
[4] As part of a Contracts for Difference (CfD) support scheme, as available in the power sector for renewable generators, strike prices refer to the price that reflects the costs of investing in a low carbon technology. Projects that have secured a CfD are paid a flat (indexed) rate for their output by receiving a top-up payment on the average market price (the reference price).

Section 4: Technologies

This section explains the technologies covered in this report. Explanations are based on the *Hydrogen supply chain: evidence base* that Element Energy put together for BEIS in late 2018.[5]

CCUS-enabled methane reformation

Steam methane reformer with carbon capture, usage and storage (SMR with CCUS)

A Steam Methane Reformer (SMR) is a mature production process in which an external heat source provides high-temperature steam for the reforming reaction that produces hydrogen and CO2 from a gas source, such as methane. Any excess steam can be used to generate power, which is sufficient to meet the power demand of the overall plant. This report assumes that SMR plants achieve a conversion efficiency of 74% (HHV).

There are two main sources of CO2 emissions; one source is the CO2 that is produced alongside hydrogen in the reforming reaction, with the other being the CO2 produced by the external heat source that provides the high-temperature steam for the reaction. The process of capturing CO2 is far simpler for the former, with the capture of CO2 from fuel combustion being relatively expensive, as it needs to be separated from nitrogen. Overall, 90% of all CO2 is assumed to be captured.

Due to the design of the plant, SMRs cannot be readily turned down and it takes a number of days to turn on or off. Therefore, an SMR acts very much as a baseload producer, i.e. a producer that is operating at constant (usually high, up to 95%) load factors year-round.

The technology varies in scale but is most likely to be deployed in the 100s of MW scale. This report covers a 300MW and a 1000MW illustrative example for 2020 to 2050 online years to show the impact of economies of scale, however other sizes are possible. Whilst 2020 has been included for comparison purposes, SMR with CCUS can only come forward once a CO2 transport and storage (T&S) infrastructure is in place. The technology's technical life is assumed to be 40 years.

Autothermal Reformer with carbon capture and storage (ATR with CCUS)

An Autothermal Reformer (ATR), unlike an SMR, is 'self-heating' (autothermal) as it partially combusts some of the natural gas feed to generate heat for the endothermic reforming reaction. To achieve partial combustion, oxygen is often used instead of air, which requires stripping out nitrogen. Whilst this requires an additional Air Separation Unit (ASU) and creates significant additional power demand that needs to be imported (a proportion of which could be

[5] Element Energy (2018), 'Hydrogen supply chain evidence base' (viewed on 18 June 2021).

offset by electricity generated from the heat of the hydrogen CO2 mix coming out of the reformer), it avoids the need for expensive post combustion separation of CO2 from nitrogen (required in an SMR). The autothermal process allows ATRs to achieve higher conversion efficiencies and, due to only a single CO2 stream, higher CO2 capture rates than SMRs. This report assumes a conversion efficiency of 84% (HHV) and a CO2 capture rate of 95%.

Due to the high-temperature thermal processes, an ATR's output cannot be readily turned on and off. Whilst, unlike SMR, it has some ability to ramp up and down it remains far slower at doing so than an electrolyser. Therefore, an ATR acts very much as a baseload producer, i.e. a producer that is operating at constant (usually high, up to 95%) load factors year-round.

The technology is most likely to be deployed in the 100s of MW scale. This report covers a 300MW and a 1000MW illustrative example for 2020 to 2050 online years to show the impact of economies of scale, however other sizes are possible. Whilst 2020 has been included for comparison purposes, ATR with CCUS can only come forward once a CO2 T&S infrastructure is in place. The technology's technical life is assumed to be 40 years.

Autothermal Reformer with Gas Heated Reformer with carbon capture, usage and storage (ATR+GHR with CCUS)

A Gas Heated Reformer (GHR) could be added to a methane reformer, typically to an ATR, improving the overall conversion efficiency of the plant. This report assumes a conversion efficiency of 86% (HHV). This is based on simulation estimates undertaken by Jacobs in 2018 and should be considered aspirational as a future case, given that the GHR design is less proven at scale. This is achieved as the hot gases coming off the ATR are used to heat a mixture of natural gas and steam as it enters the GHR, which is partially reformed to produce a mixture of syngas (CO, CO2 & H2), unreacted methane and steam. The gases then pass to the ATR which completes the conversion to syngas and the gas from the ATR is then used to heat the methane and steam coming into the GHR in a continuous process. The GHR process means that more power needs to be imported as the heat of the hydrogen CO2 mix coming out of the reformer cannot be used to generate electricity.

Like a standard ATR, the high-temperature thermal processes mean an ATR+GHR cannot be readily turned on and off but has some ability to ramp up and down, however far slower than an electrolyser. Like ATR, ATR+GHR has a single CO2 stream, from the reformer, therefore high CO2 capture rates of 96% can be achieved.

The technology is most likely to be deployed in the 100s of MW scale. This report covers a 300MW and 1000MW example for 2025 (earliest technical availability in Element Energy dataset) to 2050 online years to show the impact of economies of scale, however other sizes are possible. The technology's technical life is assumed to be 40 years.

Electrolysis

Electrolysis is the process of using electricity to split water into hydrogen and oxygen. There are plans for electrolysis units or plants to be built in various sizes into the 100s of MW scale, however these larger projects plans are made up of a series of smaller modules or stacks. Currently, stack sizes are typically up to 5 MW in size.

Alkaline electrolysis

Alkaline electrolysis is the most mature form of electrolysis with around 90 years of operational experience. In alkaline electrolysis the reaction that separates the water into hydrogen and oxygen occurs between two electrodes in a solution composed of water and liquid electrolyte. Alkaline’s electrical conversion efficiency is assumed to increase from 77% in 2020 to 82% for a plant coming online in 2050. Alkaline’s ability to ramp up and down is quicker than that of gas reforming plants. However, when compared to other electrolyser technologies, such as Proton Exchange Membrane (PEM), it is slower at responding to a fluctuating power supply, so it might be more difficult and costly to pair them with renewable energy sources efficiently.

The levelised costs presented in this report assume different operating modes for electrolysis, including grid-connected, dedicated electricity sources and curtailed electricity. Each configuration assumes different load factors. For our calculations we have assumed a 30-year lifetime for Alkaline electrolysis, with a plant size of 10MW (made up of smaller stacks) for online years from 2020 to 2050.

Proton Exchange Membrane electrolysis

Proton Exchange Membrane (PEM) electrolysis splits water by using an ionically conductive solid polymer and is assumed to achieve electrical conversion efficiencies of 72% in 2020 up to 82% for a plant coming online in 2050. PEM electrolysis offers rapid dispatchability and turn down to follow energy output, for example from renewables. Therefore, it is ideal for pairing with, for example, dedicated wind farms for low carbon hydrogen production or the provision of rapid response to the grid.

Like for Alkaline, the report shows different operating modes, including grid-connected, dedicated electricity sources and curtailed electricity. For our calculations we have assumed a 30-year lifetime for PEM electrolysis, with a plant size of 10MW (made up of smaller stacks) for online years from 2020 to 2050.

Solid Oxide Electrolysis

Whilst Alkaline and PEM electrolysis are both low-temperature electrolysis, Solid Oxide Electrolysis (SOE) uses high-temperature electrolysis (~500 degrees centigrade). Although SOE is not yet widely available commercially, it is included in this report due to the potential of the technology at large scale, once mature. One advantage of SOE is that the higher temperatures render electrolysis more efficient. The report assumes a conversion efficiency of 74% in 2020 up to 86% for plants coming online in 2050. If, in addition, the temperature can be created through waste heat, electrical efficiencies over 100% can be achieved. Note, that in this report, for simplicity, we assume that waste heat can be accessed at £0/MWh. This is an optimistic scenario and SOE would be more expensive if the price for waste heat was non-zero. One possible future application is to pair SOE with future nuclear power sources, where it can benefit from both high-temperature heat and electricity from the same source. However, due to the high temperatures required, SOE is less suitable for cycling but is expected to be capable of a cycle in less than one day.

For our calculations we have assumed a mature SOE technology, with a 30-year lifetime and a size of 10MW (made up of smaller stacks) for online years from 2020 to 2050. Whilst 2020 has been included for comparison purposes, SOE is not yet available at MW scale.

CCUS-enabled biomass gasification

Gasification is a mature technology that heats a solid feedstock, such as coal or biomass, in a reduced concentration atmosphere (to avoid combustion) comprising air, oxygen or steam to produce a synthetic gas (syngas). Hydrogen is then separated out of the syngas. Whilst various different feedstocks can be gasified, this report focuses on biomass. Biomass feedstocks can include almost any organic material including purpose grown woody crops (e.g. short rotation beech), purpose grown herbaceous crops (e.g. grasses), agricultural waste, commercial waste and dry sewage waste. For simplicity, our analysis assumes that plants consume biomass wood pellets. In general, information on gasification technologies with CCUS is sparse and this report includes one example of biomass gasification with CCUS (also referred to as Bio-Energy with Carbon Capture and Storage (BECCS)). BEIS is currently undertaking further work on gasification technologies to improve the evidence base. This will include getting a better understanding of the costs faced by First-Of-A-Kind (FOAK) projects. The Element Energy data underlying this report does not make a distinction between FOAK and Nth-Of-A-Kind (NOAK) projects. This report therefore only covers 2030 to 2050 online years. The technology is most likely to be deployed in the 100s of MW scale. This report covers a 59MW and a 473MW illustrative example to highlight economies of scale, however other sizes are possible. The technology's technical life is assumed to be 30 years.

Other technologies

The above does not represent an exhaustive list of hydrogen production technologies. There are other technologies, including newer technologies such as Natural Gas Partial Oxidation (POX) or Compact Hydrogen Generation (CHG) using Sorption Enhanced Reforming (SER). These technologies integrate previously independent process steps and can achieve superior efficiency. These more novel technologies are not covered in this report, but BEIS will be considering these further in the future. Additionally, it is important to note that some of the technologies covered in the report by E4tech and the Ludwig-Bölkow-Systemtechnik (LBST) on behalf of BEIS on a low carbon hydrogen standard[6] have not been considered for LCOH at this stage, but future work will explore these further. They include CCUS-enabled gasification that uses residual mixed waste as a feedstock, gas reforming with CCUS that uses biogas formed from food waste and the Chlor-alkali process, which is an electrolytic process that produces H2 as a by-product from water and salt.

[6] E4tech and LBST (2021), 'Report on a Low Carbon Hydrogen Standard' (viewed in July 2021).

Section 5: Production cost assumptions

Section 5 sets out a short description and source for each production cost assumption that underlies our LCOH estimates.

Technology cost and technical assumptions

Technology costs are based on the *Hydrogen supply chain: evidence base* that Element Energy put together for BEIS in late 2018.[7] The annex, published alongside this publication, puts the information in a more user-friendly format and into 2020 prices.

Capital expenditure (CAPEX)

For CCUS-enabled methane reformation, CAPEX covers the reformer unit, power island (steam turbine), all other necessary balance of plant, civil works (building and foundations), electricity (where relevant) and gas grid connection and a CO2 dehydration & compression unit. For SMR plants it also includes a unit for CO2 removal from flue gas, whilst for ATR plants it also includes an air separation unit.

For electrolysis, CAPEX covers the electrolyser system (the stack), all necessary balance of plant (drier, cooling, de-oxo and water de-ionisation equipment), civil works (building and foundations) and electricity grid connection.

For gasification, CAPEX covers the gasifier, syngas treatment unit, an air separation unit, a shift conversion unit, an acid gas removal unit, a sulphur recovery unit, a CO2 drying & compression unit and a methanator unit to convert residual carbon oxides. Grid connection costs are not included as required process electricity is assumed to be produced using a portion of the syngas produced from the relevant input feedstock (for example biomass).

Note our CAPEX estimates do not include cost of hydrogen compression equipment. See further detail below under 'Hydrogen compression costs'.

[7] Element Energy (2018), 'Hydrogen supply chain evidence base' (viewed on 18 June 2021).

Literature Review of CAPEX

Given that the technology costs used in this report are based on a publication from 2018 and that hydrogen is a fast-moving space, a literature review was undertaken to compare our CAPEX estimates (the largest LCOH component after fuel costs) to a range of external sources to verify the continued relevance of our evidence. To compare the external estimates to our evidence base, several conversions and calculations had to be undertaken. This includes, adjusting to a 2020 price base, converting from $ and € to £, converting from LHV to HHV and converting from kWe to kW H2. In the case of kWe to kW H2, some sources gave conversion efficiencies. If these were not provided, the Element Energy conversion efficiencies for the relevant technology were applied.

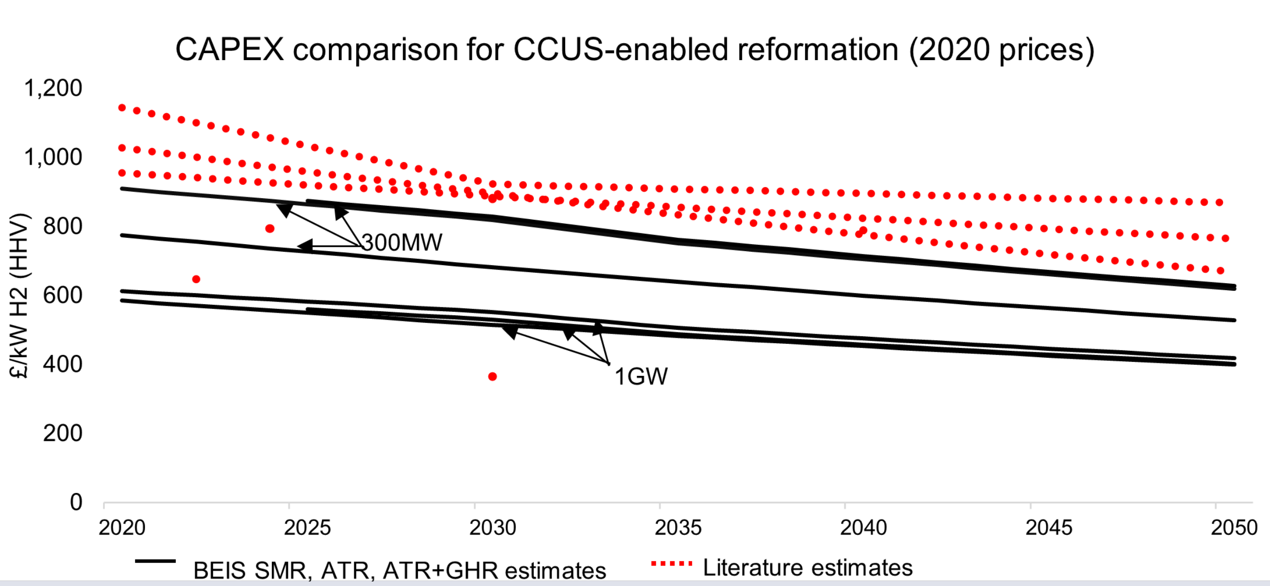
Whilst there are other important components of LCOH, we found insufficient coverage in the literature to provide a comprehensive review and draw reliable conclusions.

We found ample literature on electrolysis production methods, with less coverage of CCUS-enabled methane reformation technologies. For electrolysis technologies we have considered studies, generally with a global focus, by Bloomberg New Energy Finance (BNEF)[8], the International Energy Agency (IEA)[9], Imperial College London[10], the Energy Systems Catapult[11], and Deloitte[12]. Studies focusing on CCUS-enabled methane reformation technologies, also with a global focus, are sparser and we have included Wood[13] and the IEA. For both CCUS-enabled methane reformation and electrolysis technologies we also considered published information from the HySupply Competition[14] and modelling assumptions used in recent reports by Aurora[15] and National Grid[16]. Note, for CCUS-enabled technologies we have only included SMR, ATR and ATR+GHR technologies and excluded newer technologies such as PoX. For electrolysers, we have included Alkaline and PEM.

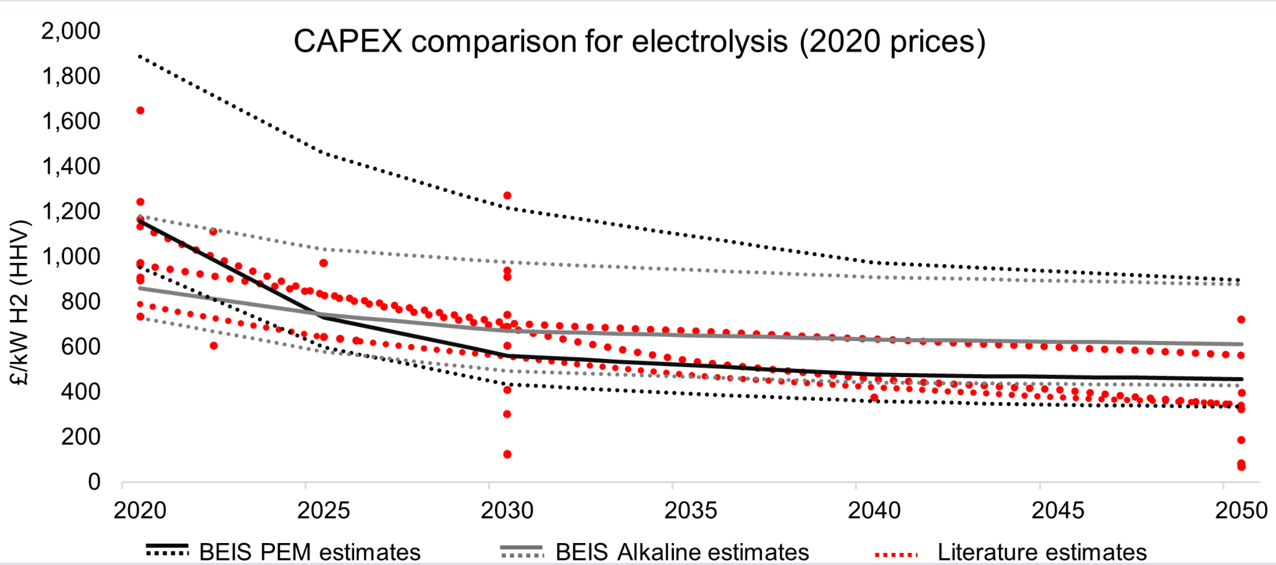
For CCUS-enabled methane reformation, most of the external estimates we considered give CAPEX £/kW H2 HHV estimates based on plant sizes of around 300MW. Time series modelling assumptions used by Aurora are based on their own review of literature with most of the primary sources based on large-scale (1GW+) plants, whilst National Grid's CAPEX time series is assumed to be relevant for different size plants (from 100MW to 1GW+). The chart below compares our 300MW and 1GW plant CAPEX assumptions against the literature estimates. The external time series modelling

[8] Bloomberg NEF (2019), 'Hydrogen - The Economics of Producing Hydrogen from Renewables' (viewed on 18 June 2021).
[9] IEA (2019), 'The Future of Hydrogen' (viewed on 18 June 2021).
[10] Imperial College London, Grantham Institute (2017), 'Future cost and performance of water electrolysis: An expert elicitation study' (viewed on 18 June 2021).
[11] Energy Systems Catapult (2020), 'Nuclear Energy for Net Zero' (viewed on 18 June 2021).
[12] Deloitte (2020), 'Investing in hydrogen' (viewed on 18 June 2021).
[13] BEIS/Wood (2018), 'Assessing the Cost Reduction Potential and Competitiveness of Novel (Next Generation) UK Carbon Capture Technology' (viewed on 18 June 2021).
[14] BEIS (2020), 'Low Carbon Hydrogen Supply Competition' (viewed on 18 June 2021).
[15] Aurora (2020), 'Hydrogen for a Net Zero GB: An Integrated Energy Market Perspective' (viewed on 18 June 2021).
[16] National Grid ESO (2020), 'Future Energy Scenarios' (viewed on 18 June 2021).

assumptions and IEA estimates are slightly higher than our cost estimates for different plant sizes. Our data reflects economies of scale, resulting in significantly lower costs for larger sites. The near-term individual data points, from the Hydrogen Supply Competition and Wood (for 200-350MW sites) align more closely with our estimates. Improving our understanding of First-of-a-Kind projects and economies of scale linked to moving to larger sites represents an area of future work.



For electrolysis, whilst our central estimates align with those assumed in other recent studies by National Grid and Aurora, there is generally a wide variation in data points in 2020 and 2030. Whilst our upper end cost data envelopes the upper end of literature estimates, our lower bound estimates are more conservative than some other sources. This becomes most prominent by 2050 when many datapoints are lower than our CAPEX assumptions. This is likely to reflect more bullish global demand and deployment scenarios driving down technology costs, but also switches to larger stack sizes (not considered in our data) providing economies of scale. Improving our assumptions around technological learning represents an area of future work.



Variable and fixed operating expenditure (OPEX)

Variable and fixed operating costs refer to all technology specific costs incurred and exclude fuel costs, which are considered separately below.

For CCUS-enabled methane reformation and gasification, variable OPEX refers to all necessary consumables (excluding fuel costs which are captured below), such as water, chemicals, and catalysts, whilst fixed OPEX generally refer to direct labour, administration/general overheads, insurance/local taxes and maintenance.

For electrolysis, variable OPEX refers to annuitised stack replacement costs. Stack costs make up 60% (PEM), 50% (Alkaline), 60% (SOE) of plant CAPEX and are assumed to need replacement every 11 (PEM), 9 (Alkaline), 7 (SOE) years over a 30-year technology technical lifetime. Fixed OPEX, like for reformers, generally refers to direct labour, administration/general overheads, insurance/local taxes and maintenance.

Note, our OPEX estimates do not include cost of hydrogen compression equipment. See further detail below under ‘Hydrogen compression costs’.

Hydrogen compression costs

This report currently does not include hydrogen compression costs. These costs are incurred if the produced hydrogen is injected directly into a high pressure (typically >8.5 Megapascal (MPa)) transmission network or stored (at significantly higher pressure than the transmission network) due to supply and demand variation. For injection into a distribution network at lower pressures (typically <0.7 MPa), compression would not be needed.

Most CCUS-enabled technologies output hydrogen at around ~2 MPa, whilst electrolysis is assumed to output hydrogen at around ~3 MPa. Work is underway to attempt to increase this to >8 MPa for PEM electrolysis and up to 6 MPa for Alkaline, which would allow at least PEM electrolysis to directly inject into a transmission network. Therefore, most technologies would incur compression costs if they were to inject directly into a transmission network. All technologies would incur costs if the hydrogen had to be stored. It is our assumption that only larger sites would connect directly to a transmission network and as compressor CAPEX and fixed OPEX costs come down significantly with scale, they are unlikely to make up a large portion of the overall levelised cost (for a 300MW site producing hydrogen at a constant/high load factor year-round they would add around £1/MWh).

Given significant uncertainty around the timings of a transmission, distribution and storage network emerging (with dedicated shorter distance pipelines being a potential interim solution) and uncertainty around which projects would connect where, we have excluded these costs for levelised cost purposes but will consider these further going forward.

Efficiency

For electrolysis, efficiencies refer to the overarching efficiency of the plant including the electrolyser stack itself and the wider necessary balance of plant in turning MWh electricity input into MWh (HHV) hydrogen output. For reformers and gasification technologies, efficiencies refer to the conversion efficiency of MWh fuel/feedstock/electricity input and MWh (HHV) of hydrogen output.

Build and lifetime

Build times and technical life of technologies vary by technology and project. In this report we use a generic three-year build time and a technical life of 30 years for electrolysis and gasification projects and 40 years for reformer projects. We will continue to update our evidence base in this area and we also invite stakeholders to share evidence with us.

Cost reductions

Cost reduction assumptions, just like technology costs above, are based on the *Hydrogen supply chain: evidence base* that Element Energy put together for BEIS in late 2018.[17] Cost reductions can affect CAPEX and OPEX directly or production costs more generally through improvements in plant efficiencies. The main drivers of cost reductions are:

- Global technological learning
- Local/UK specific learning-by-doing
- Economies of scale

Our cost estimates reflect global technology learning for all technologies and economies of scale for some technologies. Local/UK specific learning is not reflected in our LCOH estimates, meaning that cost reductions from moving from a First-Of-A-Kind (FOAK) to a Second-Of-A-Kind (SOAK) or Nth-Of-A-Kind (NOAK) plant or other learning-by-doing is not reflected. These are however important considerations and should be considered further going forward.

For CCUS-enabled methane reformation, an average annual CAPEX reduction due to global technological learning of 1.26% (based on historic evidence) is assumed for SMRs whilst for the newer ATR and ATR+GHR an additional 10% reduction in costs to 2030 is assumed to reflect that these newer technologies will be catching up with more established technologies, such as SMR, followed by the same trend as for SMRs post 2030. No further cost reductions or efficiency improvements are assumed for technologies over time. In addition to global technological learning, all types of plants experience significant CAPEX reductions due to economies of scale. The effect on LCOH is however less pronounced, as technologies are assumed to run at maximum load factors, making CAPEX a small component of LCOH. This report is reflecting this by presenting both a 300MW and 1000MW plant size.

For electrolysis, the main cost reductions for CAPEX and OPEX and through efficiency improvements over time are driven by global technological learning driven by demand for and uptake of electrolysis. Whilst moving to larger plants also results in economies of scale on the stack and balance of plant, these drive cost reductions less due to the modular approach to

[17] Element Energy (2018), 'Hydrogen supply chain evidence base' (viewed on 18 June 2021).

sites (i.e. electrolyser plants in the 10s or 100s of MWs are made up of individual smaller sized stacks). This report assumes a 7% cost reduction per doubling in installed global capacity for PEM electrolysis. Total installed global PEM capacity was less than 50MW in 2018. Alkaline electrolysis is a more mature technology with lower expected cost reduction. Our literature review has shown that our cost reduction assumptions over time might be conservative. Future work will explore this further.

For gasification, our evidence assumes good technology development opportunities that have potential to reduce CAPEX and OPEX directly or LCOH through efficiency improvements, including potential for reduced parasitic power loads, move towards second generation gasifiers, more active CO2 removal solvent and more efficient CO2 compression. Gasification also experiences significant cost reductions due to economies of scale.

Electricity prices and load factors

To show a range of representative LCOH estimates, we have assumed three types of electricity sources and prices. Technologies could be consuming a mixture of these, however for simplicity this report focuses on the three stylised scenarios. The below sets these out and explains how these apply to different technologies.

Electricity from the grid

These prices are relevant for all technology types that consume electricity. Using electricity from the grid allows hydrogen producers to run at a constant, maximum load factor, equalling their availability once annual maintenance has been taken into account (around 95% for most technologies, see further detail in the annex, published alongside this report). This is referred to as 'baseload' in this report.

It is unclear at this stage what type of supplier arrangement hydrogen producers would be able to secure, where exactly they would connect to the grid (distribution or transmission) or how much of electricity policy costs they would face. For example, large industrial users benefit from exemptions. Given this uncertainty, this report showcases two grid-connected electricity prices: the industrial retail price and the industrial long run variable cost (LRVC). Both of these price series are Net Zero consistent and published by BEIS[18]. BEIS does not currently publish underlying Net Zero consistent baseload wholesale prices, which would represent the lower bound grid electricity price. Therefore, configurations where plants access wholesale prices are not covered in this report, however we note if the baseload wholesale price could be secured, levelised costs when using grid electricity would be lower. If plants choose to run at lower than maximum load factor (<95% for most technologies), they could lower their costs further by only accessing off-peak prices. We have not considered this in this report.

The industrial retail price assumes that hydrogen producers are large enough to connect to the electricity transmission network and that they face electricity policy costs in line with what other

[18] BEIS (2021), 'Green book supplementary guidance, Data tables 1 to 19: supporting the toolkit and the guidance' (viewed 15 July 2021).

industrial users face on average. Costs faced by industrial users are lower than those for other consumers (households and businesses), given where they sit in the system.

The actual purpose of LRVC is for use in social cost benefit analysis. It isolates those parts of the retail price that represent actual costs to society that vary according to the level of consumption and excludes other price components that are fixed or will only result in transfers between groups in society (which are of no net social benefit). In this report we use the LRVC as a proxy for a grid electricity price closer to a wholesale price, as some add-on costs (such as certain policy or network costs) are stripped out. We refer to this as a "wholesale price plus" in the rest of this report.

Levelised cost analysis does not take into account wider system implications of hydrogen production consuming grid electricity. This is considered in wider energy system modelling.

Electricity from dedicated electricity generation sources

These prices are only relevant for electrolysis technologies. Using electricity from dedicated sources (simplistically assuming the capacity of the dedicated source matches the capacity of the electrolyser it is connected to, i.e. no overplanting) allows electrolysis to run at the same load factor as the dedicated source (i.e. for offshore wind 51% for a 2025 online year rising to 63% for a 2050 online year). Electrolysis can connect directly to a variety of different dedicated electricity generation sources, including offshore, onshore, solar, nuclear, or combinations of these technologies including coupling with electricity storage. In this report we are showing the example of dedicated offshore wind, given its high load factor compared to other dedicated renewables.

The report currently excludes dedicated nuclear for electrolysis. It could, however, potentially play a valuable role in hydrogen production in the future through both new and existing technologies due to its ability to provide both heat and power. BEIS is in the process of developing its evidence base on different types of nuclear reactors (such as small modular reactors and advanced modular reactors). This coupled with a better understanding of high-temperature heat electrolysis (such as SOE) which could potentially improve efficiency will help us to provide useful LCOH estimates for hydrogen production from dedicated nuclear sources in the future.

For offshore wind the assumption is that the electrolysis plant would face the levelised cost of offshore wind electricity generation as their electricity price, i.e. the electrolysis plant pays for the full offshore wind generation cost. Note, we are not currently accounting for costs of private wires between the dedicated power source and the electrolysis plant. Levelised cost for offshore wind from 2025 to 2040 (assumed constant thereafter) can be found in the Electricity Generation Cost Report[19]. Note we are showing LCOH estimates using dedicated offshore wind from 2025 onwards, however in reality these sorts of projects are likely to only be able to come online later in the decade.

[19] BEIS (2020), 'Electricity Generation Costs 2020' (viewed on 18 June 2021).

Electricity from curtailment

These prices are only relevant for electrolysis technologies. Electrolysis could operate by only using curtailed, otherwise wasted electricity as input. Electricity generators are curtailed if electricity supply exceeds demand or due to localised network constraints. The resulting curtailment is unevenly distributed throughout the year, for example it is likely to be higher on high wind/sun days. However, the distribution depends on the make-up of the power sector generation mix. Generally, curtailment increases as the proportion of renewables in the generation mix increases.

Using BEIS's electricity system analysis[20] we have found that the available curtailment in low-cost, low-carbon systems, could provide electrolysis plants with an average load factor of around 25%. It is important to note that the first electrolysis plant added to such a system would benefit from a higher load factor, whilst the marginal plant, needed to ensure all curtailment throughout the year is absorbed, would face a lower load factor, with curtailment on low excess days already being absorbed by others. For our generic plants, this report assumes an average 25% load factor, which simplistically is assumed to stay constant for online years from 2020 to 2050. When using curtailed electricity, the electrolysis plant does not face the costs of building the electricity source/power sector (like in the dedicated option above) but benefits from absorbing otherwise wasted electricity.

In this report we simplistically assume there is no competition for the curtailed electricity and the electricity generator that is curtailed would have been built regardless of whether an electrolysis plant is installed or not. Therefore, the cost of this electricity is assumed to be £0/MWh. Energy system analysis needs to consider this in more detail, considering interactions between the power and hydrogen sector and also taking into account a range of flexibility and storage solutions to better understand competition. Overall, when considering the LCOH of electrolysis plants using curtailed electricity, availability of curtailment is crucial to delivery production at scale.

Fuel prices

Natural gas

CCUS-enabled methane reformation consumes natural gas. Like for electricity, it is unclear at this stage what type of supplier arrangement these plants would be able to secure and how much of gas policy costs they would face. Given this uncertainty and for consistency with grid electricity prices, this report showcases two gas prices: the industrial retail price and the industrial long run variable cost (LRVC)[21]. In the same publication, BEIS also publishes the underlying natural gas wholesale prices, which represent the lower bound central natural gas

[20] BEIS (2020), 'Modelling 2050: Electricity System Analysis' (viewed on 18 June 2021).
[21] BEIS (2021), 'Green book supplementary guidance, Data tables 1 to 19: supporting the toolkit and the guidance' (viewed 15 July 2021).

prices faced by hydrogen producers. For completeness, we have included these in the annex published alongside this report.

The industrial retail price assumes that hydrogen producers face gas policy costs in line with what other industrial users face on average.

In the power sector, given the steady consumption and long-term nature of contracts, natural gas consuming plants are able to secure prices close to the wholesale price. Indeed, the electricity generation cost report assumes gas wholesale prices for input fuel (we cover this in the annex, published alongside this report). In the main report, to ensure consistency with assumptions on electricity, we assume that plants face the industrial LRVC, as a proxy for a gas price closer to a wholesale price, as some add-on costs (such as certain policy or network costs) are stripped out.

Biomass

Biomass gasification plants are assumed to consume wood pellets. It is possible that smaller sites would consume wood chips. This report does not consider this. Prices used are in line with those assumed in the Electricity Generation Cost Report[22] for biomass conversion and BECCS plants, which are assumed to use wood pellets. We are not specifying whether the wood pellet costs refer to wholesale or retail prices.

Carbon prices

This report assumes that hydrogen production, just like electricity generation, will face a carbon price for any emissions occurred onsite (i.e. CCUS-enabled methane reformation and gasification technologies). In addition, CCUS-enabled biomass gasification produces negative emissions. For simplicity, this report values negative carbon emissions at the same carbon price as carbon emissions for the purposes of the analysis. However, as the policy area evolves, we will update our assessments. Note, electrolysis plants, even if using grid electricity, do not emit carbon onsite. These technologies face the carbon price through the cost of the electricity they consume. Additional carbon emissions incurred in the power system are not considered in LCOH but need to be considered in whole system analysis.

The report assumes that the carbon prices faced by hydrogen producers up until 2030 are the EU ETS carbon value projections as set out in Annex M to BEIS's Energy and Emission Projections under baseline policies[23]. We acknowledge that going forward the UK ETS will be determining traded carbon prices, however as the UK market is still in early stages, this report still uses the EU ETS carbon values. Updates to carbon prices will be captured in future work. Hydrogen producers are not assumed to be subject to the Carbon Price Support (CPS);

[22] BEIS (2020), 'Electricity Generation Costs 2020' (viewed on 18 June 2021).
[23] BEIS (2020), 'Updated energy and emission projections: 2019, Annex M' (viewed on 18 June 2021).

currently the CPS only applies to CO2 fossil fuel emitters in the power sector. Beyond 2030, the total carbon price increases linearly to reach the appraisal value of carbon in 2050[24].

CO2 Transport and Storage costs

CCUS-enabled hydrogen producers will face CO2 Transport and Storage (T&S) fees for using the CO2 T&S network. The T&S fee structure and methodology is currently being developed to account for the different cost drivers of T&S networks. For the purposes of LCOH we have used a simplified assumption of £28/tCO2 (2020 prices), which is based on the findings of a 2018 Uniper report[25]. Work is ongoing in BEIS to update and further refine this analysis.

Hurdle rates

Hurdle rates are defined as the minimum financial return that a project developer would require over a project's lifetime. Financing costs refer to the weighted average cost of capital (WACC) a project faces, in other words the opportunity cost of the money invested (cost of borrowing the money or the return the money could earn in an alternative investment with similar risks). This means that the WACC represents the investor's minimum required return (hurdle rate), given the investment risks. For levelised costs, the hurdle rate acts as the rate at which both costs and production are discounted across time.

Discounting represents the time value of costs and hydrogen output. It also allows to reflect the impact of technology specific risks, if the relevant information is available (see further detail below).

Lower hurdle rates allow the LCOH to be less weighted by the upfront CAPEX and more by the hydrogen produced, which is discounted less. Such projects can be interpreted as being less risky and more confident that the production throughout the project's lifetime will generate a sufficient rate of return. Higher hurdle rates make the LCOH more weighted by the upfront CAPEX and less by the hydrogen produced. Such projects can be interpreted as being less willing to take as high a risk with high capital costs, as there is less confidence that the revenue from production later will generate a sufficient rate of return.

Hurdle rates will vary across technologies, given that each project will face specific risks, cost of debt, equity and debt-to-equity ratio conditions. Also, the introduction of a hydrogen business model will affect a project's hurdle rate. The effect will differ depending on the type of business model chosen.

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[24] BEIS (2020), 'Green book supplementary guidance, Data tables 1 to 19: supporting the toolkit and the guidance' (viewed on 18 June 2021).
[25] Uniper Technologies (2018), 'CCUS Technical Advisory – Report on Assumptions' (viewed on 18 June 2021). The report quotes £23/tCO2 in 2012 prices.

Due to lack of knowledge on technology specific hurdle rates at this early stage, for levelised cost purposes, this report assumes a uniform 10% hurdle rate to discount costs and output across time. Future work will improve on this simplified assumption.

Emission factors

CCUS-enabled methane reformation and biomass gasification produce onsite greenhouse gas emissions, which are mostly captured. To estimate these emissions and the associated carbon and CO2 T&S costs we use emission factors for natural gas and wood pellets, respectively, based on BEIS Greenhouse Gas Reporting: Conversion Factors 2021[26]. For wood pellets both the CO2e consumed and stored within the feedstock over its lifetime while growing and the emissions associated with growing, pelletising, processing and transporting it are included. In addition, we also account for the negative emissions that biomass gasification with CCUS creates by removing CO2 from the atmosphere. It is important to note that biomass emissions are highly dependent on the type of feedstock used and this report only shows one possible option.

[26] BEIS (2021), 'Greenhouse gas reporting: conversion factors 2021' (viewed on 18 June 2021).

Section 6: Levelised Costs

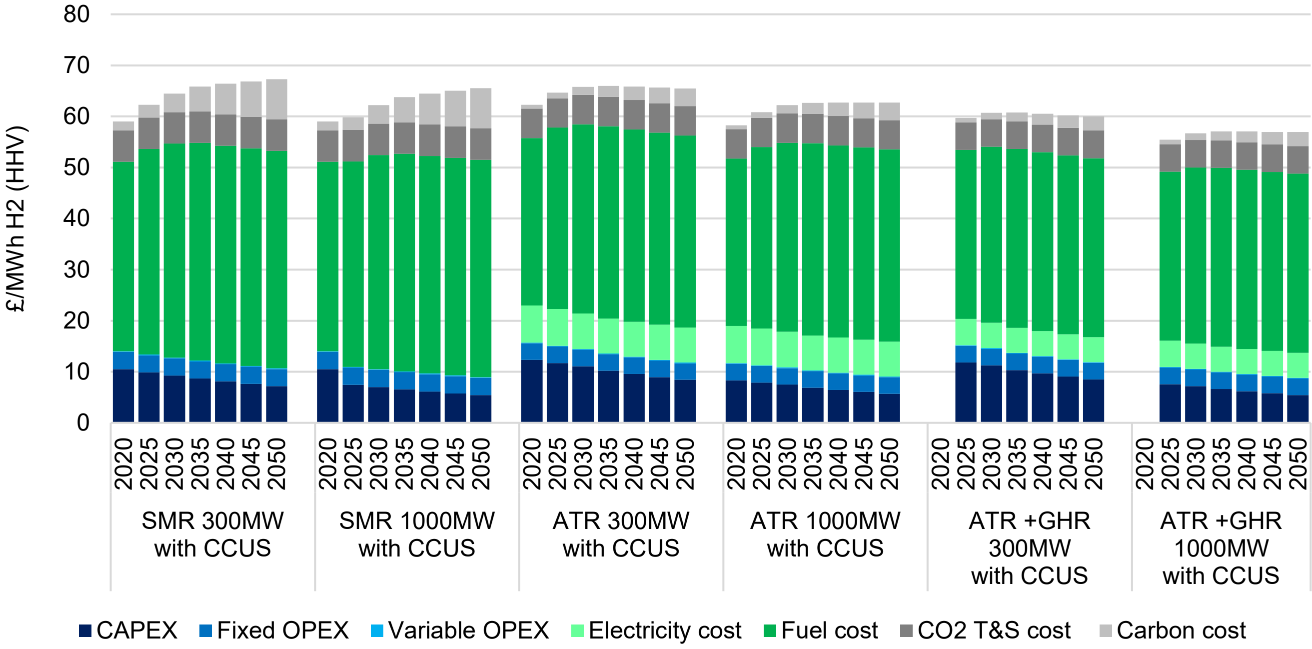
This section summarises the analysis of the levelised cost of hydrogen for a selection of core technology configurations. For CCUS-enabled methane reformation we are presenting levelised costs for the three core technologies at a 300MW and a 1000MW illustrative scale, respectively. This is to reflect economies of scale. For electrolysis we are presenting levelised costs for the three core technologies using four different types of electricity sources and associated running patterns, respectively. For CCUS-enabled biomass gasification we are presenting levelised costs for one core technology at a 59MW and 473MW scale to reflect economies of scale. All values presented in this section are in 2020 real prices.

CCUS-enabled methane reformation

Chart 6.1 shows levelised costs for online dates from 2020 to 2050 for CCUS-enabled methane reformation at baseload operation (95%), consuming natural gas and electricity (where applicable) at central industrial retail prices. LCOH for these technologies when paying “wholesale price plus*”* prices for natural gas and electricity (proxied through LRVC) and when paying just the wholesale price for natural gas are shown in the annex, published alongside this report.

The chart shows that LCOH for CCUS-enabled reformers are overall fairly constant over time as two effects take place. On the one hand, there is global technological learning, which reduces CAPEX over time, whilst on the other hand fuel and carbon costs increase. The chart also shows the effect of economies of scale, with 1000MW sites being less costly on a £/MWh basis than 300MW sites. As noted in Section 4, on a LCOH basis, when running at baseload operation, the impact of economies of scale is relatively small. The chart uses retail gas and electricity prices; if a “wholesale price plus” (proxied through the LRVC) or wholesale prices are used, LCOH are around £10/MWh lower. This additional information is shown in the annex.

Chart 6.1: LCOH estimates for CCUS-enabled methane reformation, at central retail fuel prices, commissioning from 2020 to 2050, £/MWh H2 (HHV)



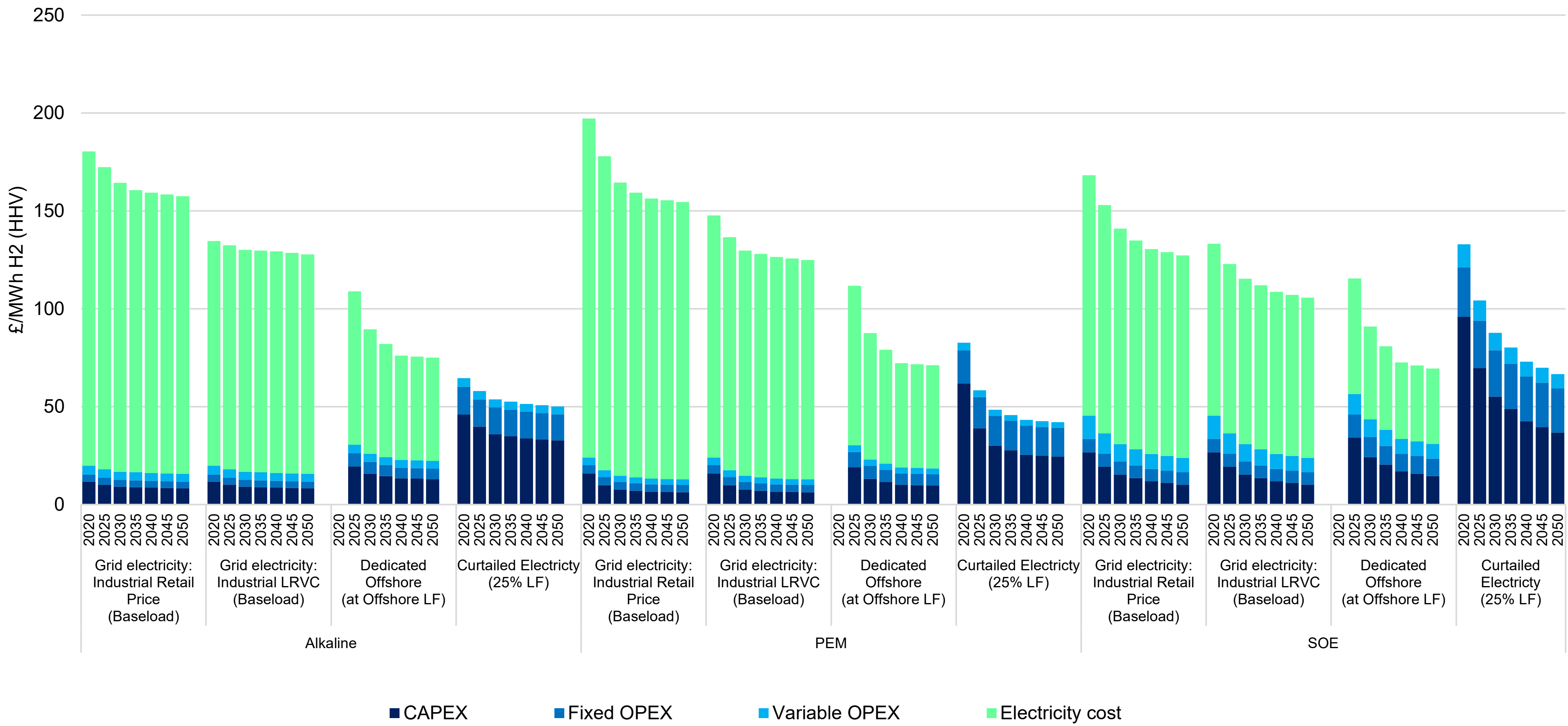
Electrolysis

Chart 6.2 shows levelised costs for online dates from 2020 to 2050 for electrolysis technologies that are grid-connected with baseload operation at a 98% load factor for Alkaline and PEM and a 90% load factor for SOE, connected to dedicated offshore wind at a 51% load factor for 2025 online dates up to a 63% load factor for 2050 online dates, and curtailment-using at a 25% load factor. When grid-connected we are showing the impact of either facing the industrial retail price or a “wholesale price plus” (proxied through LRVC). Further detail can be found in the annex, published alongside this report.

There is obviously a much larger range of combinations that could be modelled. For example, different dedicated renewable sources, mixed renewable sources or coupled with electricity storage, overplanting of renewables, or use of other low carbon generation, such as dedicated nuclear. This report does not explore all of these possibilities but notes that they will require further exploration going forward. We have shown a dedicated offshore connection as one potential example. Note, as mentioned in Section 5 above, the LCOH does not include the cost of private wires.

The chart shows that LCOH are highest when using grid electricity, for which our price series include either all (retail) or a reduced amount of policy costs (LRVC). If electrolysis plants do not face these costs, grid-connected operation would become more attractive. Dedicated offshore connection reduces LCOH, but also increases the fixed cost elements of the LCOH due to lower load factors. Using curtailed electricity does not (under our assumptions) incur electricity costs but sees significantly higher fixed costs per MWh due to lower load factors (25%). Technologies that have higher upfront costs (such as SOE) see the largest impacts.

Chart 6.2: LCOH estimates for electrolysis technologies, connected to different electricity sources, commissioning from 2020 to 2050, £/MWh H2 (HHV)

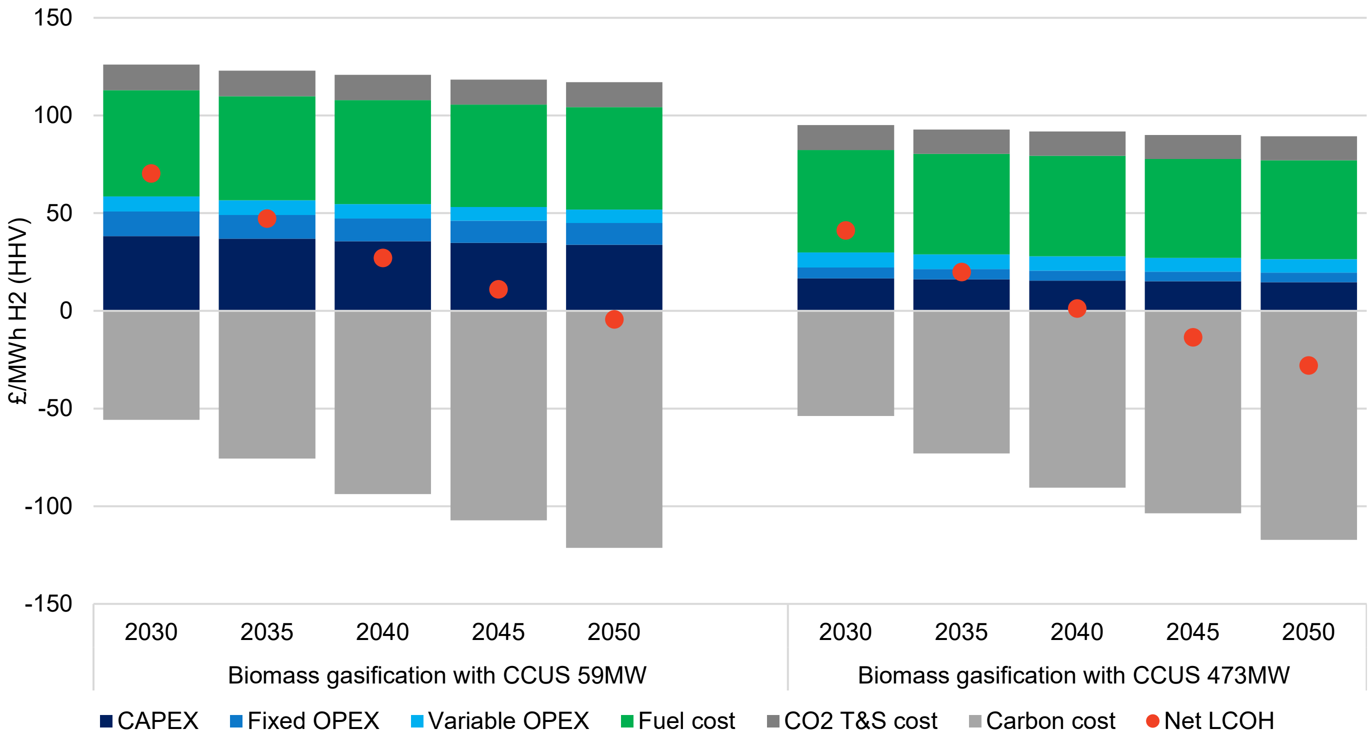


CCUS-enabled biomass gasification

Chart 6.3 shows levelised costs for online dates from 2030 to 2050 for CCUS-enabled biomass gasification. Whilst other gasification routes are possible, such as coal gasification or waste gasification, these have not been considered in this report. To show the economies of scale, this report covers both a 59MW and a 473MW illustrative plant size. Further detail can be found in the annex, published alongside this report.

The chart shows that LCOH for biomass gasification with CCUS are fairly constant over time, reducing slightly due to CAPEX learning. There are also significant economies of scale when moving to a larger site. As noted in Section 5, for simplicity, this report values negative carbon emissions at the same carbon price as carbon emissions for the purposes of the analysis. This assumption allows production costs to be partially and eventually more than offset by the value associated with negative emissions. This is demonstrated by the red “net LCOH” dots. As this policy area evolves, we will update our illustrative assessments.

Chart 6.3: LCOH estimates for CCUS-enabled biomass gasification commissioning from 2030 to 2050, £/MWh H2 (HHV)



Overarching conclusions

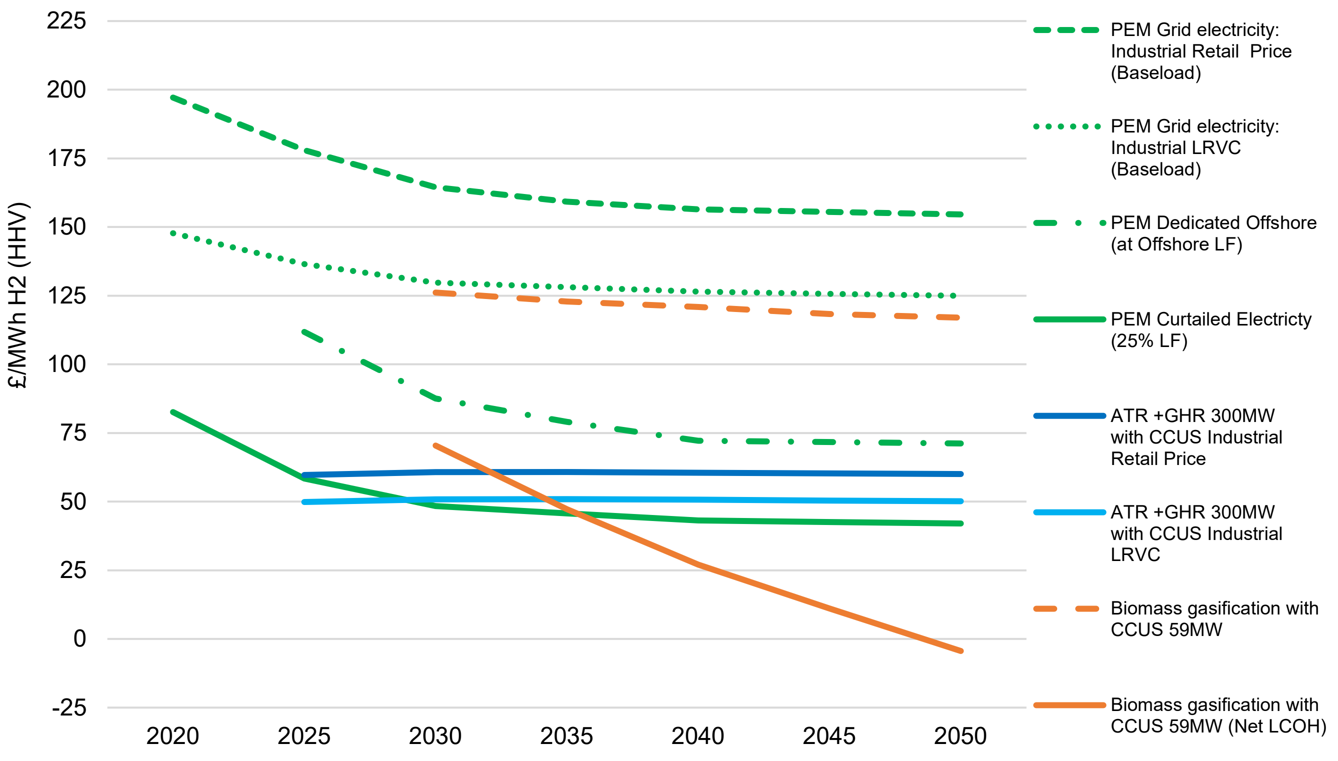
Chart 6.4 summarises and compares the findings from 6.1, 6.2 and 6.3. To keep the chart manageable, it focuses on one electrolyser technology (PEM), one CCUS-enabled methane reformation technology (ATR+GHR 300MW with CCUS) and a 59MW biomass gasification with CCUS plant, but all data is available in the annex, published alongside this report.

The chart shows that currently CCUS-enabled methane reformation technologies are the lowest cost hydrogen production technology. However, over time and depending on fuel price assumptions, different electrolysis configurations are coming down in costs and in some cases become cost competitive with CCUS-enabled methane reformation technologies. It is not possible to determine precise LCOH 'switch points' between different technologies as these vary depending on the different assumptions made.

For example, PEM using only curtailed electricity could become cost competitive from 2025 onwards. Importantly, curtailment by 2030 is likely to be limited, with the actual amount dependent on build out in the power sector, and electrolysers would have to compete with other flexible technologies and solutions (such as Demand Side Response, storage, interconnection), which may mean less electricity available for electrolysers or increasing prices for curtailed electricity (i.e., not £0/MWh, which is assumed in the estimates in this report). The limited amount of curtailment means that, even if electrolysers are cost competitive (through use of curtailed electricity), hydrogen production would be at low volumes, at least in the short term.

Biomass gasification with CCUS is relatively high cost, but the value associated with the negative emissions assumed for this analysis results in rapidly declining and even negative costs to 2050. As this policy area evolves, we will update our illustrative assessments.

Chart 6.4: Comparison of LCOH estimates across different technology types at central fuel prices commissioning from 2020 to 2050, £/MWh H2 (HHV)



Section 7: Sensitivities

Levelised cost estimates are highly sensitive to the underlying data and assumptions used. Within this, different technologies are sensitive to different input assumptions.

To illustrate some of the key uncertainties around our levelised cost estimates, Charts 7.1-7.4 present the impact on LCOH of plants coming online in 2025 for the following sensitivities:

- High/low retail fuel and grid electricity prices for all technologies
- High/low CAPEX, OPEX and efficiency information for electrolysis technologies
- 10 percentage point higher/lower load factor sensitivity for electrolysis when using curtailed electricity

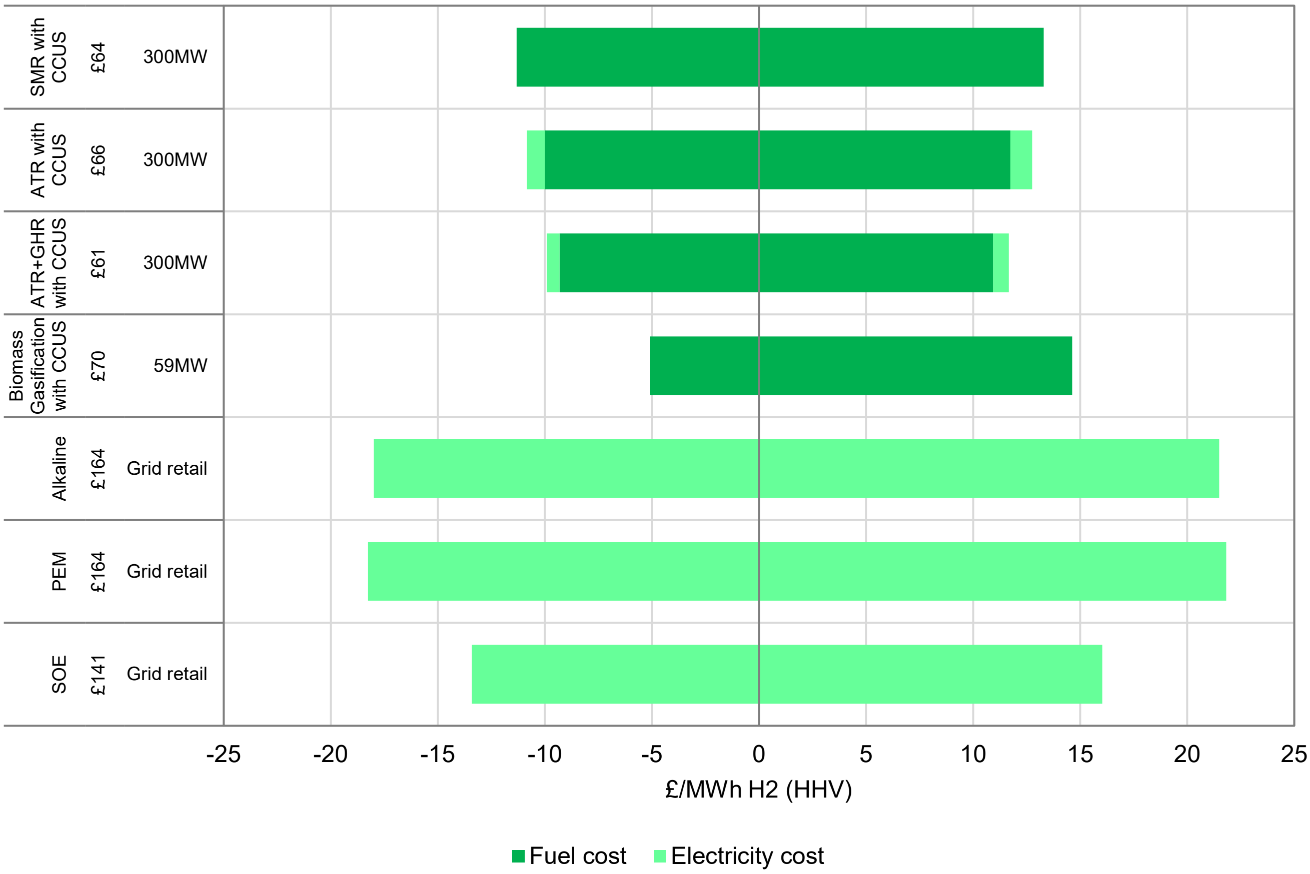
Whilst these sensitivities test some of the most important drivers of LCOH, there are likely to be other sensitivities. However, these have not been tested in this report. The annex, published alongside this report, includes data for all online dates to 2050.

Fuel and electricity price sensitivity

Chart 7.1 shows the impact on central LCOH (shown for reference on the vertical axis) of varying fuel (natural gas for CCUS-enabled methane reformation and biomass for CCUS-enabled gasification) and grid electricity prices, relevant to all technologies except for SMRs and gasification for a 2030 online year. 2030 is chosen as all technologies are assumed to be available by that year. Other years for technologies where these are available are covered in the annex, published alongside this report. Whilst the chart focuses on retail prices (except for biomass, where prices refer simply to the cost of wood pellets), the annex shows additional sensitivity results when a “wholesale price plus” (proxied by LRVC) is assumed. The chart also only focuses on small plants (300MW for methane reformation with CCUS and 59MW for biomass gasification with CCUS) as the difference to large sites (due to similar efficiencies) was insignificant. The annex captures the larger units as well.

For plants coming online in 2030 the chart shows that by moving from central to low/high fuel and electricity prices, LCOH vary by up to £13/MWh for CCUS-enabled methane reformation technologies. The impact reduces for more efficient technologies, like ATR+GHR with CCUS. The LCOH of electrolysis technologies varies by up to £22/MWh. The impact is larger for electrolysis due to generally lower efficiencies, with the exception of SOE, which has higher efficiencies than other forms of electrolysis and shows similar impacts as for CCUS-enabled technologies. Biomass prices are assumed to have a larger upward than downward risk, therefore LCOH increase by up to £15/MWh if high biomass prices are used but only reduce by £5/MWh if low biomass prices are used.

Chart 7.1: Impact of high/low retail fuel/electricity prices on LCOH estimates for technologies commissioning in 2030, £/MWh H2 (HHV)

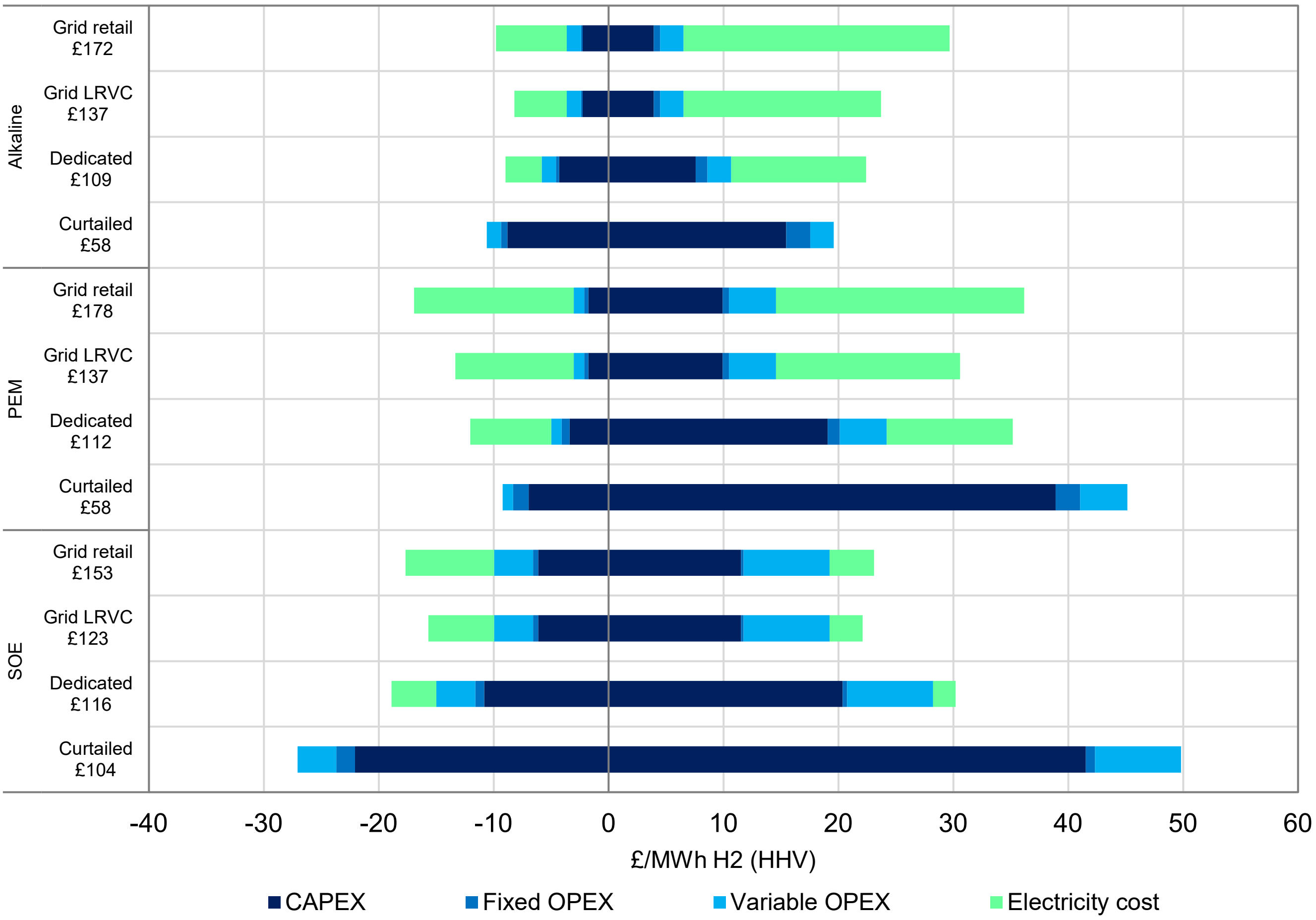


Technology cost and efficiency sensitivity

The Element Energy evidence base provides us with high and low technology costs (CAPEX and OPEX) and efficiencies for electrolysis technologies, which are significantly more uncertain than CCUS-enabled methane reformation and gasification technologies. Chart 7.2 shows the impact on central LCOH (shown for reference on the vertical axis) of varying technology costs and efficiencies.

It shows that LCOH could vary substantially with higher or lower assumptions. The right-hand side of the chart shows the impact of a high-cost scenario coupled with lower efficiency, whereas the left-hand side shows the impact on LCOH of a low-cost scenario along with higher efficiency. The impact of high/low fixed cost (CAPEX and fixed OPEX) on LCOH increase with lower load factors, as we move from grid-connected electrolysis to only using curtailed electricity. The size of the impact of high/low efficiencies is strongly linked to the electricity price assumed. The highest price (industrial retail price) results in the biggest swing, whilst efficiencies do not have an impact on LCOH if the electricity price is £0/MWh (assumed for curtailed electricity). As Alkaline is the most mature technology, there is less uncertainty and LCOH are impacted the least out of all three technologies. The newest form of electrolysis, SOE, faces the largest uncertainty and as such LCOH are impacted the most, with the exception of efficiencies, which vary less than for other technologies and therefore results in lower LCOH variation.

Chart 7.2: Impact of high/low cost and efficiency on LCOH estimates for electrolysis commissioning in 2025, £/MWh H2 (HHV)

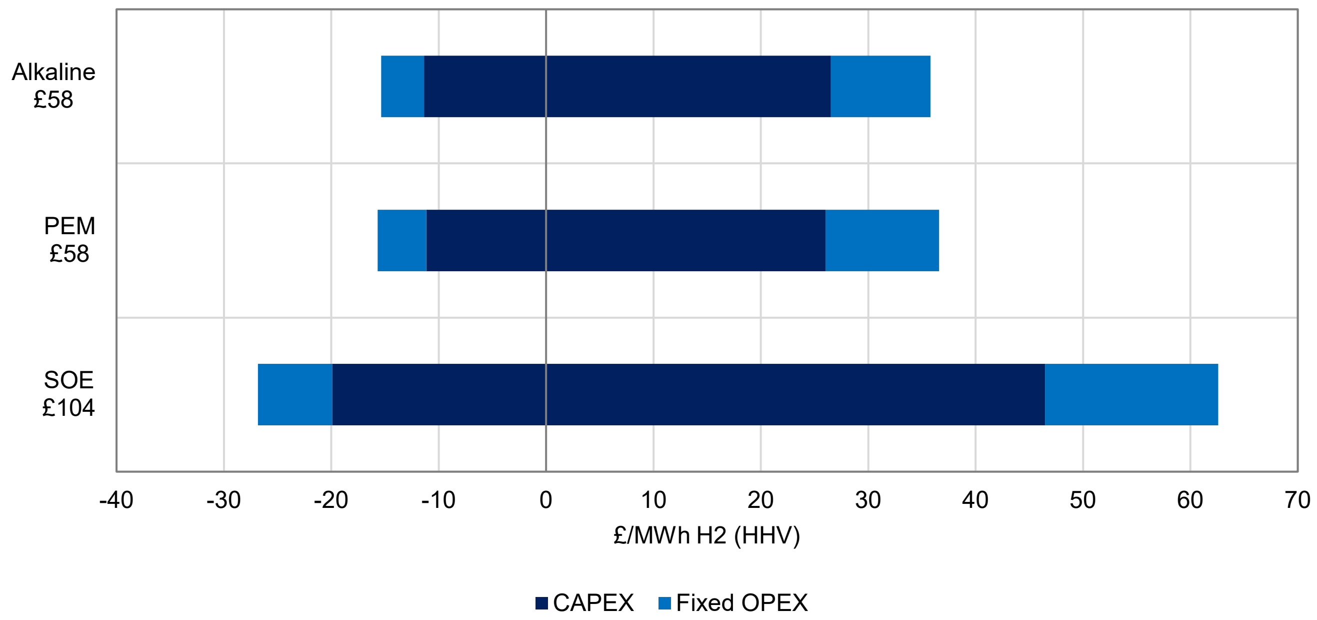


Load factor sensitivity

Whilst all assumed load factors are uncertain and will depend on the system the technologies will operate in, the shape of demand and the amount of hydrogen storage, we are focusing the sensitivity testing on the assumed 25% load factor for electrolysis using curtailed electricity. If those plants assumed to run at a baseload maximum load factor (equal to availability) had lower load factors LCOH would increase. This is not explored in this report.

Chart 6.4 shows the impact of a 10-percentage point higher/lower load factor (i.e. 15% and 35%). As curtailed electricity is assumed to be £0/MWh, the change only affects the fixed CAPEX and OPEX elements of the LCOH. The larger the fixed costs, the more a change in load factors affects the LCOH. For example, SOE LCOH varies significantly more than for PEM and Alkaline. A reduction in load factors to 15% has a bigger impact on LCOH than an increase to 35% due to the exponential relationship between load factors and costs.

Chart 7.4: Impact of 10 percentage point higher/lower load factor when using curtailed electricity commissioning in 2025, £/MWh H2 (HHV)



Overarching conclusions

The use of different sensitivities has shown that LCOH estimates are subject to large uncertainties and has highlighted the importance of considering the individual circumstances of technologies and scenarios. Certain technologies may be heavily impacted by a scenario change, whereas other may not.

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